ConocoPhillips Alaska

Well WD-02
Permit No. AK-1I003-B
UIC Permit Renewal Application
Class I (Industrial)

Colville River Unit
North Slope, Alaska

August 1, 2018

ConocoPhillips
Alaska

Jessika L. Gonzalez
Permitting Coordinator
ConocoPhillips Alaska, Inc.
Health, Safety & Environmental
P.O. Box 100360
Anchorage, AK 99510-0360
Phone: (907) 265-6213
Email: Jessika.L.Gonzalez@ConocoPhillips.com

August 1, 2018

Certified Mail
Return Receipt Request
7018 0360 0000 6624 5121

Edward J. Kowalski
Director, Office of Compliance and Enforcement
U.S. Environmental Protection Agency-Region 10
1200 Sixth Avenue, Suite 155, OCE-101
Seattle, Washington 98101

Re: Class I Underground Injection Control Permit Renewal Application
Permit Number AK-1I003-B - Class I Well WD-02
Colville River Unit (CRU), North Slope, Alaska

Dear Mr. Kowalski:

ConocoPhillips Alaska, Inc. (CPAI) hereby submits a Class I well permit renewal application for an existing disposal well in the Colville River Unit. The permit renewal is for well WD-02 located at the Colville Delta No. 1 (CD1) pad on Alaska North Slope. The well is currently permitted by the U.S. Environmental Protection Agency (EPA) as a dedicated Class I disposal well.

The existing permit AK-1I003-B and the authorization to inject expires on February 2, 2019.

CPAI requests that the EPA renew and extend services under permit AK-1I003-B for the Class I disposal well WD-02. CPAI also requests that the existing WD-02 monitoring and operating practices currently in use be incorporated in the renewed Class I permit.

Please find the enclosed permit renewal application for your reference. If you have any questions or need additional information, please contact me at (907) 265-6213.

Sincerely,

Jessika L. Gonzalez
Permitting Coordinator

Enclosures

Cc: Ryan Gross, EPA (2 hard copies)
Evan Osborne, EPA (Electronic)
Tim Mayers, EPA (Electronic)
Chris Wallace, AOGCC (Electronic)
Marc Bentley, ADEC (Electronic)

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Class I UIC Renewal Application

Document Declaration

This Underground Injection Control (UIC) Renewal Application for a Class I Industrial well permit is submitted to the U.S. Environmental Protection Agency - Region 10 by ConocoPhillips Alaska Inc. The disposal site is located on the North Slope of Alaska in the Colville River Unit, Alpine Field, Colville Delta No. 1 Pad (CD1).

The renewal Application has been prepared per the U.S. Code of Federal Regulations, Title 40 - Protection of the Environment; Part 124 Subpart A, which outlines procedures; Part 144, which lists general program requirements; and Part 146, which provides specific program criteria and standards. The Application is formatted per instructions and guidance provided by the EPA on prior Class I applications.

Official communication regarding the Application should be directed to:

Misty Alexa, WNS Operations Manager
ConocoPhillips Alaska Inc.,
P.O. Box 100360
Anchorage, AK 99510
(907) 670-4024

Comments regarding clarification of facts and other inquiries may be directed to:

Jessika L. Gonzalez, Permitting Coordinator
ConocoPhillips Alaska Inc.,
PO Box 100360, ATO-19-1960
Anchorage, Alaska 99510
(907) 265-6213

OMB No. 2040-0042 Approval Expires 12/31/2018

EPA

United States Environmental Protection Agency

Underground Injection Control Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number AK1I003-B

	T/A	C
U		

Read Attached Instructions Before Starting

For Official Use Only

Application approved (mo day year)	Date received (mo day year)	Permit Number	Well ID	FINDS Number

II. Owner Name and Address			III. Operator Name and Address		
Owner Name: ConocoPhillips Alaska, Inc.			Owner Name: ConocoPhillips Alaska, Inc.		
Street Address: P.O. Box 100360; 700 G. Street		Phone Number: (907) 265-6213	Street Address: P.O. Box 100360; 700 G. Street		Phone Number: (907) 265-6213
City: Anchorage	State: AK	ZIP CODE: 99503	City: Anchorage	State: AK	ZIP CODE: 99503

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
[x] Yes [ ] No	[x] Private [ ] Federal [ ] Other	[ ] Owner [x] Operator	1300; 2900

VIII. Well Status *(Mark "x")*

[x] A. Operating	Date Started (mo day year): 07/26/1999	[ ] B. Modification/Conversion	[ ] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

[x] A. Individual	[ ] B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
		1	1	Colville Delta No. 1 (CD-1) Pad Colville River Unit

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
I	I		One well (WD-02), Class 1, Type I

XI. Location of Well(s) or Approximate Center of Field or Project

70.3505249, -150.9279078

Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Township and Range Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
70	20	39.8	150	55	23.3	32	12N	5E	SE	444FSL		2052FE	

XII. Indian Lands (Mark 'x')

[ ] Yes
[x] No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
Misty Alexa, WNS Operations Manager	(907) 670-4024
C. Signature: Misty Alexa	D. Date Signed: 30 July 2018

EPA Form 7520-6 (Rev. 12-11)

EXECUTIVE SUMMARY

In this Underground Injection Control (UIC) application, ConocoPhillips Alaska, Inc. (CPAI) requests that the Environmental Protection Agency (EPA) renew and extend the existing permit AK-1I003-B for the existing Class I disposal well WD-02. The existing permit expires on February 2, 2019. CPAI also request that the existing WD-02 monitoring and operating practices currently in use be incorporated into the renewed Class I permit.

WD-02 permit, AK-1I003-A, was originally issued by EPA on February 3, 1999 and expired on February 3, 2009. CPAI submitted to renew and extend services under Permit AK-1I003-A on December 12, 2008 and EPA re-issued the UIC permit, AK-1I003-B, on January 30, 2009 with an effective date of February 3, 2009.

The WD-02 well is located on the Colville Delta No. 1 Pad (CD1) pad in the Colville River Unit (CRU), which is part of the Alpine Field on Alaska's North Slope. The Alpine Field is located approximately seventeen miles west of the North Slope road system, and currently consists of six drilling pads, connecting roads, and two airstrips. In addition to the six drilling pads, there is also the proposed Greater Mooses Tooth 2 (GMT2) development project located approximately 8.5 miles southwest of GMT1. These surface facilities along with the GMT2 proposed development project are shown in Exhibit 1-3. Class I injection is critical to the Alpine Field because it is remote and isolated from other North Slope infrastructure with no year-round connecting road to disposal facilities in other locations, and very limited space for waste storage.

There are currently two Class I disposal wells located on the CD1 pad; WD-02 and CD1-01A (see EPA Permit Number AK-1I010-B), both injecting into the Ivishak geological formation at 9200 feet. The system was designed in 1997 to provide an integrated approach to managing wastes generated from oil production, maintenance operations, the camp sewage system, and some lesser volumes generated by drilling operations.

Alpine operations use the grind-inject method to handle muds and cuttings from drilling operations, as well as oily production solids coming from wellwork operations and vessel and pipeline cleanouts. The facility-wide waste disposal system consists of a solids processing plant that normally discharges exempt drilling wastes to individual production well annuli or to the dedicated Class I disposal well CD1-01A. A separate pipeline network collects domestic wastewater/graywater from the camp sewage system for injection into the dedicated Class I disposal well WD-02. Other hookups for intermittent disposal of batch loads consists of tankage, pumps, piping, and controls that feed the Class I wells. This system is shown schematically in Exhibit 1-6. With a project remaining life of about 20 years (2018 through 2038), the total disposal volume is projected to consist of 7.0 million barrels (MMB) of domestic wastewater/graywater with very minor volumes of produced water.

The WD-02 well is in the Alpine Field, and the EPA has previously determined that no underground sources of drinking water (USDW) exist in the Alpine Field. The EPA's documentation of this finding is in Exhibits 3-5 and 3-6. The injection zone is extensive, and while it is cut by minor natural faults, extensive and competent confining zones are present; the upper confining zone is approximately 1500' thick. Similar fluids have been successfully injected into similar storage reservoirs for many years at other North Slope locations.

Renewal of three waivers of UIC Program requirements is requested for WD-02. The waivers are consistent with 40 CFR 144.16, which allow the Director to waive program requirements when there are no USDWs to protect.

1. In order to inject drilling slurry, dirty fluids, camp wastewaters, and other smaller amounts of suspended solids, CPAI requests the EPA waive the prohibition against fracturing the injection interval as required by 40 CFR 146.13(a)(1). Proper well monitoring to define the waste storage domain and to ensure fracturing of the confining zone does not occur will continue.

2. Large volumes of rock and fluid data already exist and WD-02 has successfully operated for nineteen years. A waiver is therefore requested from the 40 CFR 146.12(e)(4)-(5) and 40 CFR 146.14(a)(8) requirements to sample and characterize formation fluids and the injection matrix.

3. North Slope well performance and the waste confinement analysis included in Section 6.0, and Appendix B, has demonstrated based on eighteen years of disposal history in the Ivishak formation at Alpine Field, that there is limited chance of breaching the arresting and confining zones. Accordingly, a waiver is requested from the stipulations of 40 CFR 146.13(b)(1) and (4) and 40 CFR 146.13 (d) for ambient monitoring in the interval lying above the injection zone.

CPAI is committed to proper well operation. Systems are in place for proper monitoring and control of all surface equipment and to guarantee mechanical well integrity. Implementation of the Alpine Waste Analysis Plan (WAP) (see Appendix A), third-party waste analysis plans and use of the waste manifesting system will insure proper waste handling. Additionally, a comprehensive Spill Prevention, Control and Countermeasures Plan (SPCC), operator training program, and spill contingency plans have been implemented. With these systems in place, contamination of surface waters will not occur from deep well injection.

Disposal operations at Alpine involving two Class I injection wells is the most environmentally sound and cost effective method for permanent disposal of industrial non-hazardous and camp wastes, and one that meets the goal of minimal surface discharge and storage. In addition, CPAI has demonstrated the corporate commitment and financial resources necessary to implement a successful Class I injection program at the Alpine Field, including annual financial assurance to guarantee proper well abandonment.

CPAI requests that the EPA renew and extend services under the existing permit AK-1I003-B for the Class I disposal well WD-02. CPAI also requests that the existing WD-02 monitoring and operating practices currently in use be incorporated into the renewed Class I permit.

Acronyms and Definitions

ACF	Alpine Central Processing Facility
ADEC	Alaska Department of Environmental Conservation
AOGCC	Alaska Oil and Gas Conservation Commission
AOR	Area of Review
APDES	Alaska Pollution Discharge Elimination System
Aquifer	Subsurface water (Fresh or Saline)
ASRC	Arctic Slope Regional Corporation
BLM	Bureau of land Management
BOP	Blow Out Preventer
Borehole	The hole drilled by the bit in the rock
BPD	Barrels Per Day
BPM	Barrels per Minute
Brine	Saline waters
CBL	Cement Bond Log
CD1	Colville Delta No. 1 pad
CFR	Code of Federal Regulations
cmt	Cement
cp	Centipoise. A measure of fluid viscosity
CPAI	ConocoPhillips Alaska, Inc.
CPF2	Central Processing Facility 2
CRU	Colville River Unit
csg	Casing
CTU	Coil Tubing Unit
cuft	Cubic feet
Density	Log – Measures the density of the bulk formation, rock and fluids
DIL	Log - Dual Induction. Measures electrical conductivity of formation
DV	Special casing collar used to pump fluid/cement through
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
Fish	A piece of equipment lost downhole.
FM (Fm)	Formation
frac	Fracture
G/I	Grind and Inject (Disposal technology)
GMT1	Greater Mooses Tooth Unit 1
GMT2	Greater Mooses Tooth Unit 2
GR	Log - Gamma Ray. Measures natural radiation of the formation
GR	Gauge Ring. A tool run downhole

KOP	Kick Off Point
kppm	Thousand parts per million
KRU	Kuparuk River Unit
Liner	A casing string that does not reach the surface
LNG	Liquefied Natural Gas
M	Thousand
MB	Thousand Barrels
MD	Measured Depth
md	Millidarcy - rock permeability
md ft	Millidarcy feet (product of permeability and sand thickness)
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MITIA	Mechancial Integrity Test on the Inner Annulus
MM	Million
MMB	Million Barrels
MMSCFD	Million Cubic Feet per Day
NGL	Natural Gas Liquids
NPDES	National Pollutant Discharge Elimination System
O & G	Oil and Gas
PBTD	Plug Backed Total Depth
perfs	Perforations (wellbore holes)
PF (P/F)	Permafrost
PFO	Pressure Fall Off
pH	Measure of acidity
pkr	Packer (Wellbore sealing/isolating devise)
POH	Pull out hole. (Referrs to drill string, pipe)
ppg	Pounds per Gallon
ppm	Parts per million
pressure	Usually a smaller volume used to repair an undesirable situation.
psi	Pounds per square inch (pressure)
psig	Pounds per square inch gauge
PWI	Produced Water Injection
QA/QC	Quality Assurance/Quality Control
RCRA	Resource Conservation Recovery Act
Rig	Drilling rig and associated equipment
RIH	Run In Hole (Refers to drill string, pipe)
SDWA	Safe Drinking Water Act
SG	Specific Gravity (water = 1.0)
Shoe	The end of a casing string

SP	Log - Spontaneous Potential
SPCC	Spill Prevention, Control and Countermeasure Plan
Squeeze	A term used to indicate fluid/cement injected under resistive
SRT	Step Rate Test
SS/ss	Subsea (depth)
SSSV	Subsurface Safety Valve
Sx (sx)	Sacks
Tbg	Tubing
TD	Total Depth
TDS	Total Dissolved Solids
TOC	Top of Cement
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
WAP	Waste Analysis Plan
WMT	Waste Management Team
ZEI	Zone of Endangering Influence

<u>Symbols</u>

#	Pounds or Number
lb/gal (#/gal)	Pounds/gallon
%	Percent
F	Fahrenheit
C	Centigrade
‘	Foot or Feet
“	Inches
ft3	Cubic feet

1.0 PROJECT DESCRIPTION

1.1 Project Overview

The Alpine Field is a roadless development located on the North Slope of Alaska in the Colville River Unit (CRU). It is approximately 17 miles west of the Kuparuk River Unit (KRU) and is approximately 8 miles north of the Village of Nuiqsut. See Exhibits 1-1 through 1-4.

The Alpine Field is currently composed of six drill pads, connecting roads, and two airstrips. The Alpine Central Processing Facility (ACF) is located on the Colville Delta No. 1 (CD1) pad. See Exhibit 1-4 for additional detail. The facility currently handles approximately 66,000 barrels per day (BPD) of oil, 180 million cubic feet per day (MMSCFD) of gas, and 60,000 BPD of produced water. Exhibit 1-5 provides a production system overview.

The ACF oil handling system consists of two stages of gas and water separation and a single stage of dehydration. Two production heaters are used to aid oil/gas separation. Once crude oil is processed, it is cooled and transported to the Trans-Alaska Pipeline System (TAPS) via Alpine Pipeline to the KRU and the Kuparuk Pipeline to Pump Station 1 of TAPS.

The ACF gas handling system consists of compression, fractionation and dehydration. Gas is scrubbed and routed through a series of compressors. Liquid hydrocarbons generated by fractionation, expansion and/or compression are captured and blended with the crude oil stream, or blended with dry gas to form miscible injection (MI) fluids. MI and dry gas is re-injected into the producing formation(s) to maintain production rates and improve crude recovery.

The ACF produced water handling system consists of injection pumps and piping. Produced water is mainly routed to the injection pumps where it is re-injected into the producing formations to maintain production rates and increase crude oil recovery. Produced water may also be sent via hard line to WD-02.

1.2 Waste Disposal System

The Alpine Field practices aggressive waste minimization. Wherever possible, material use is reduced, excess material is reused on another project or material is recycled. Any hazardous/universal waste generated onsite is collected, temporarily accumulated, and shipped offsite to permitted treatment, storage and disposal facilities as per the Resource Conservation and Recovery Act (RCRA) requirements. Non-hazardous, non-liquid waste, that cannot be reused or recycled, is sent to local landfills or to an on-site incinerator. Non-hazardous, liquid waste is managed via Alaska Pollutant Discharge Elimination System (APDES) surface discharge (where appropriate) or via underground injection wells (where appropriate). All personnel involved in waste management are trained to ensure that local, state and federal rules and regulations, applicable waste analysis plan requirements, and company procedures are complied with.

There are currently two Class I disposal wells for the Alpine Field, both located on the CD1 Pad: CD1-01A and the subject of this application WD-02. A generalized waste stream diagram is shown in Exhibit 1-6. Some routine waste streams (domestic wastewater/graywater) are hard piped to WD-02; other waste streams can be sent to the WD-

02 and CD1-01A underground injection wells via tanker truck or other transport methods in batches. Batched fluid transfers are tracked and managed using the North Slope Manifest form.

Wastes for WD-02 are currently received via hard piping from the Wastewater Treatment Plant and produced water from the produced water pump injection manifold, but trucks can also offload to the WD-02 well. An equipment description and procedure for WD-02 operation is included in Exhibit 1-8.

Flow rate and pressure gauge transmitters are installed with an alarm system to detect excess injection pressures and rates. The well is monitored 24 hours a day during injection. The well operates at a maximum 3200 pounds per square inch gauge (psig) wellhead pressure and an annulus pressure up to 1500 psig. Continuous, recorded monitoring of volumes of hard piped waste streams are captured through the Alpine automation system.

1.3 Support Functions

The Alpine Field is continuously manned by operational personnel. Additionally, the Alpine Field has security detail and support personnel. All Alpine personnel are housed in a camp located on the CD1 pad. Camp and facility power is provided by onsite generation. The primary power generation device is a 25.8 mega-watt turbine supplemented by smaller units as power needs dictate. Power generation, production, permanent support facilities (warehouses) and camp facilities are equipped with fire alarm and suppression systems, manual systems, and other systems required for the protection of people, property and the environment. Personnel and supplies are transported via the seasonal ice road or by aircraft. The Alpine Field is equipped with a 3000-foot gravel airstrip adjacent to the CD3 pad and a 5000-foot gravel airstrip adjacent to the CD1 pad. The airstrips accommodate small prop driven aircraft such as Twin Otters and is suitable for larger re-supply aircraft such as DC-6s.

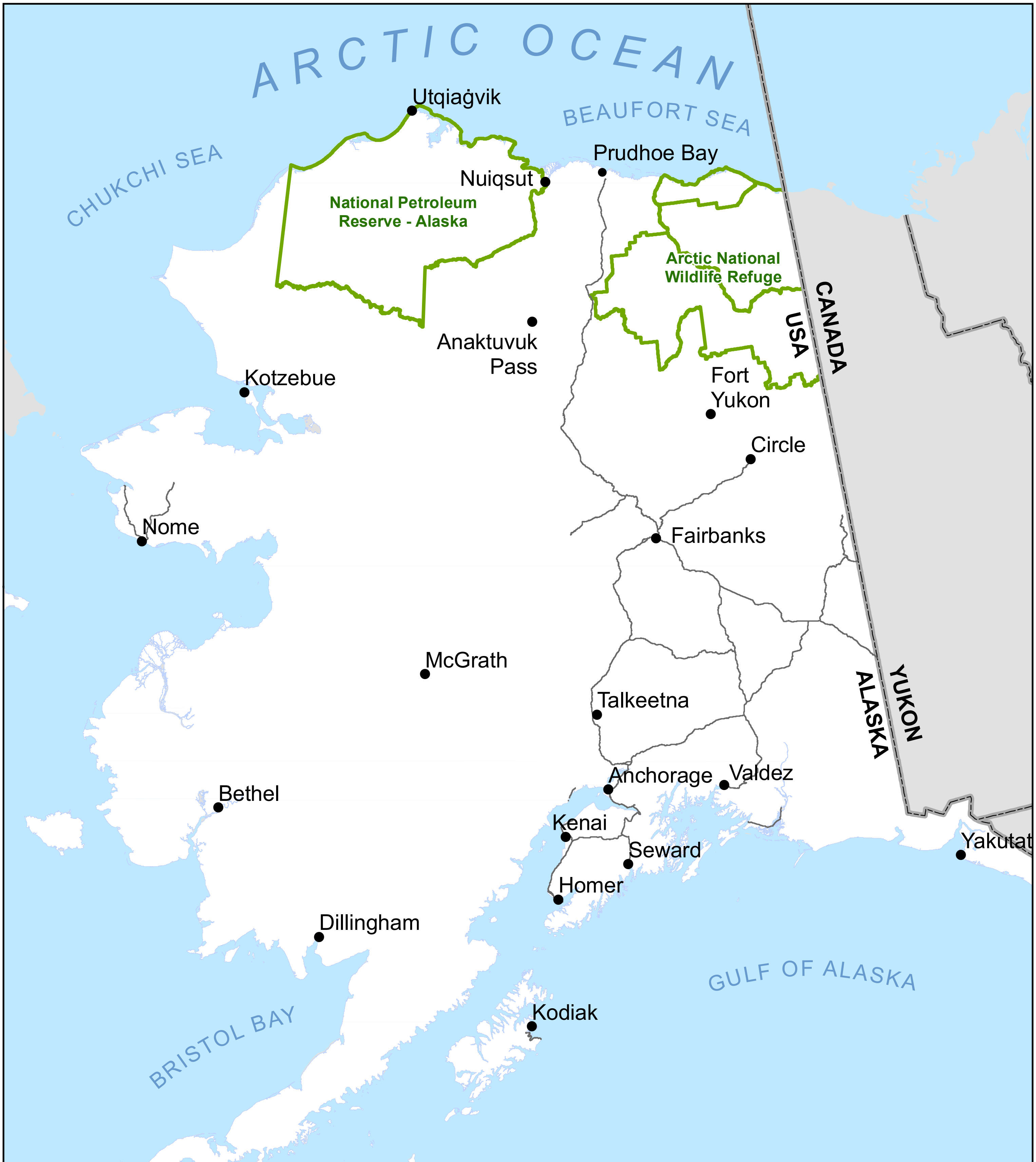


Exhibit: 1-1

State of Alaska

N

ConocoPhillips
Alaska, Inc.

0 50 100 Miles

April 16, 2018

Document Name: ALP_CD1_01A_UIC_ClassI_StateofAlaska

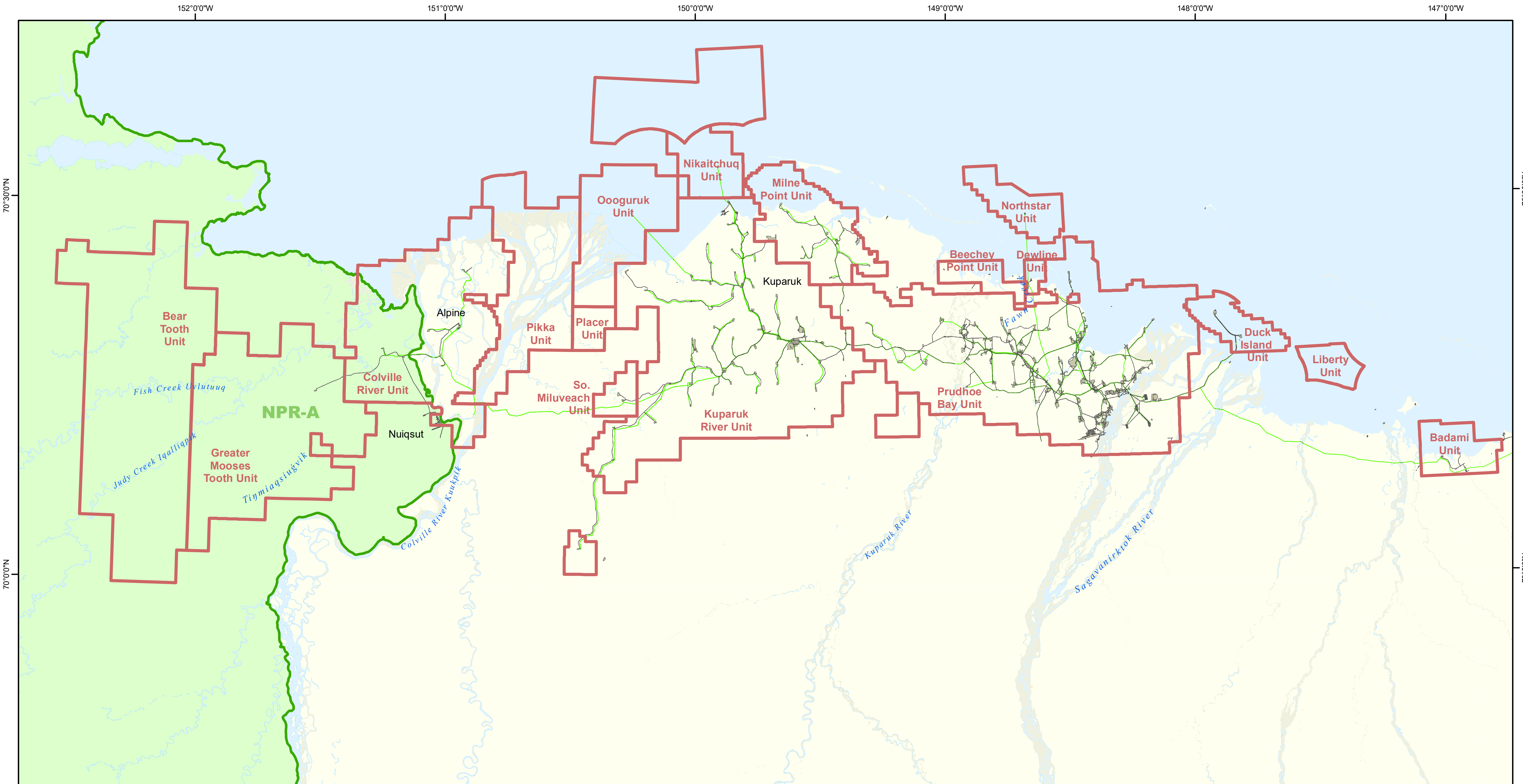


Exhibit: 1-2

North Slope Oil and Gas Units

Document Name: ALP_CD1_01A_UIC_ClassI_NS_Units.mxd

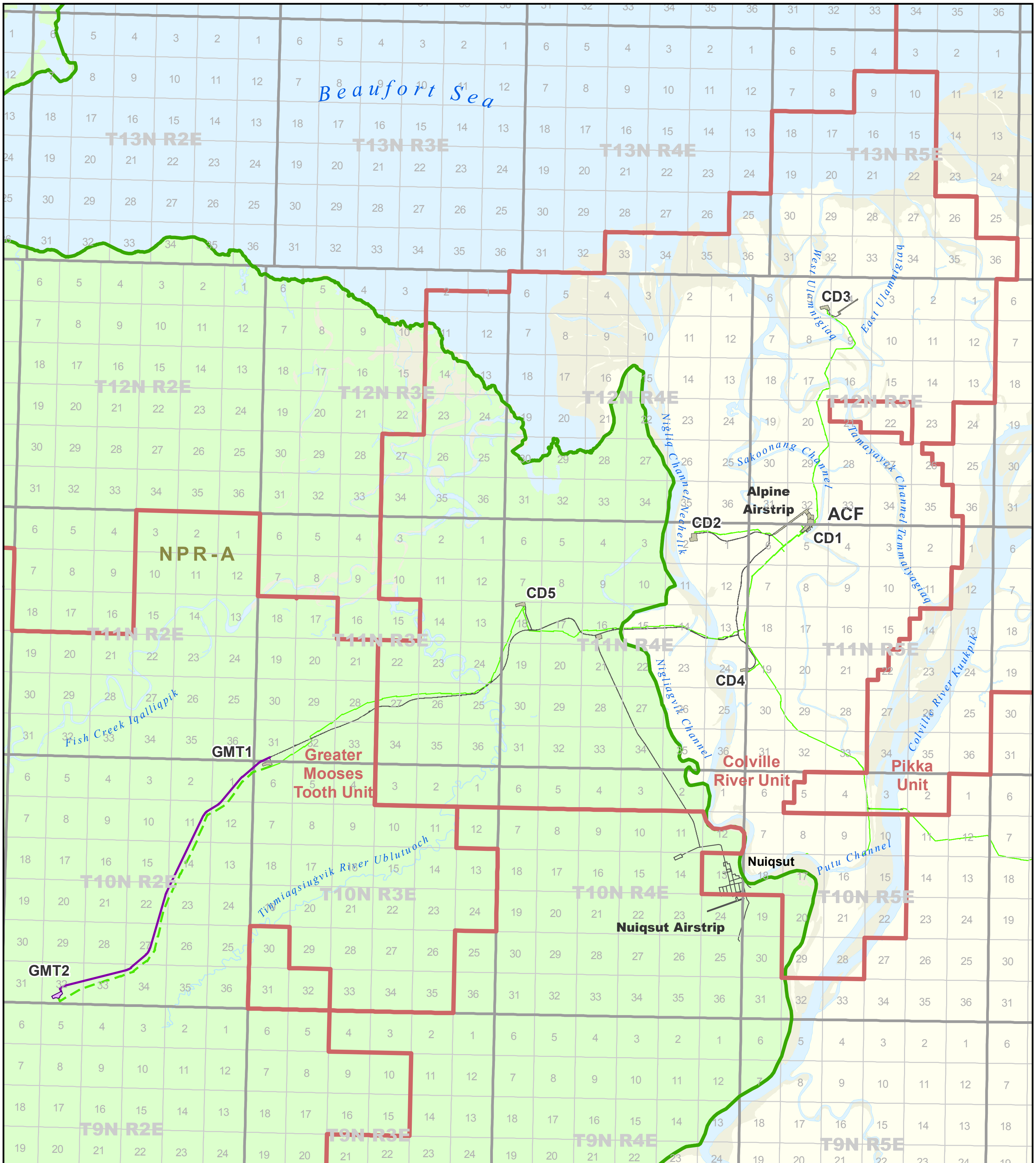


Exhibit: 1-3

Colville River Unit

Infrastructure

- Pipeline
- Pad
- Road

GMT2 Proposed

- Pipeline
- Pad
- Road

Boundaries

- Unit
- BLM (NPR-A)

N

ConocoPhillips
Alaska, Inc.

0 1 2 3 Miles

July 31, 2018

Document Name: ALP_CD1_01A_UIC_ClassI_CRU_v2

Exhibit 1-4 CD1 Site Plan

LEGEND

- LAYDOWN AREAS
- PERMANENT MOVEABLE STRUCTURES
- RUN OFF CONTROL AREA
- ABOVE-GROUND UTILITIES
- DRILL RIG ACCESS ROW
- 50' NO FUEL BUFFER LINE
- BULL RAIL

PERMANENT MOVEABLE STRUCTURES

NUMBER	UNIT
4	AIRPORT TENT
5	NDE OFFICES (X-RAY)
6	M/I OFFICE
8	NANUQ/CONAM
11	MI SWACO, HALIBURTON OFFICE
23	SCAFFOLDING WAREHOUSE
25	TELECOM
ENV-1	ENVIROVAC – NEAR J8
ENV-2	ENVIROVAC – NEAR J1
ENV-3	ENVIROVAC – NEAR TRIPLE WIDES
ENV-4	ENVIROVAC – NEAR A8 REIM
B1	SMOKE SHACK – WEST OF TITAN TENT

NOTES

1. THIS MAP IS INTENDED FOR CONCEPTUAL PURPOSES ONLY. NOT INTENDED FOR CONSTRUCTION.
2. FOR THE LOCATION OF UNDERGROUND UTILITIES, SEE DRAWING CE-AP00-660D60.
3. PROPOSED ACX MODULES WERE TAKEN FROM MAPS PREPARED BY NANA/COLT ENGINEERING DATED JULY 31, 2002, DRAWING NUMBERS SK- PD-CF00-0001 REV. A, SK-PD-CF00-0002, REV A AND PD-CF00-101-1 REV. 30.
4. PIPELINE R.O.W. CORRIDOR RESTRICTED AREA, CONTACT CONOCOPHILLIPS ALASKA PIPELINES FOR MORE INFORMATION.

GRAPHIC SCALE

100 50 0 300

(IN FEET)
1 INCH = 100'

KUUKPIK LCMF LLC
Alpine Survey Office

ConocoPhillips Alaska, Inc.

ALPINE — MODULE: AP00 — UNIT: AP

ALPINE PAD
MASTER SITE PLAN
ALPINE FACILITY

REFERENCE DWG NO/SHT NO:		
PD-CF00-101	1&2	REV 3A
PD-CF10-101	1	
PD-CFPW-103		
PD-CF00-118	6 OF 7	ALPINE FACILITIES RAW WATER INTAKE SYSTEMS

REV	DATE	REVISIONS	BY	CHK	JOB ENGR	PROJ ENGR	CUST APP
44	5/29/17	UPDATED PER K170003ACS	GD	CZ			MR
43	5/15/16	UPDATED PER K160003ACS	TRB	DB			MR
42	5/24/15	UPDATED PER K150003ACS	CZ	GD			MR
41	7/24/14	UPDATED PER K140003ACS	CZ	DB			MR
40	5/18/14	UPDATED PER K140003ACS	AG	DB			MR
39	9/28/13	UPDATED PER K130003ACS	MO	GD			MR
38	6/1/13	UPDATED PER K130003ACS	AG	DB			MR
37	6/8/12	UPDATED PER K120003ACS	CZ	GD			MR
36	12/17/11	UPDATED PER K110003ACS	CZ	GD			MR
35	9/16/11	UPDATED PER K110003ACS	CZ	GD			MR
34	6/16/11	UPDATED PER K110003ACS	CZ	DB			MR
33	6/9/11	UPDATED PER K110003ACS	AG	DB			MR

DATE: 1-11-02	DRAWN: GD	DESIGN: –	ECM NO: K02001ACS
SCALE: 1"=100'	CHECKED: JZ		CC NO: –
	APPROVAL: MR		CADD FILE NO: 02-01-09-1
JOB NO: 00-204	SUB JOB NO:	DRAWING NO: CE-AP00-115	PART: 1 OF 1 — REV: 44

DO NOT SCALE — ABOVE SCALE FOR REFERENCE ONLY

Exhibit 1-5 General Production Process

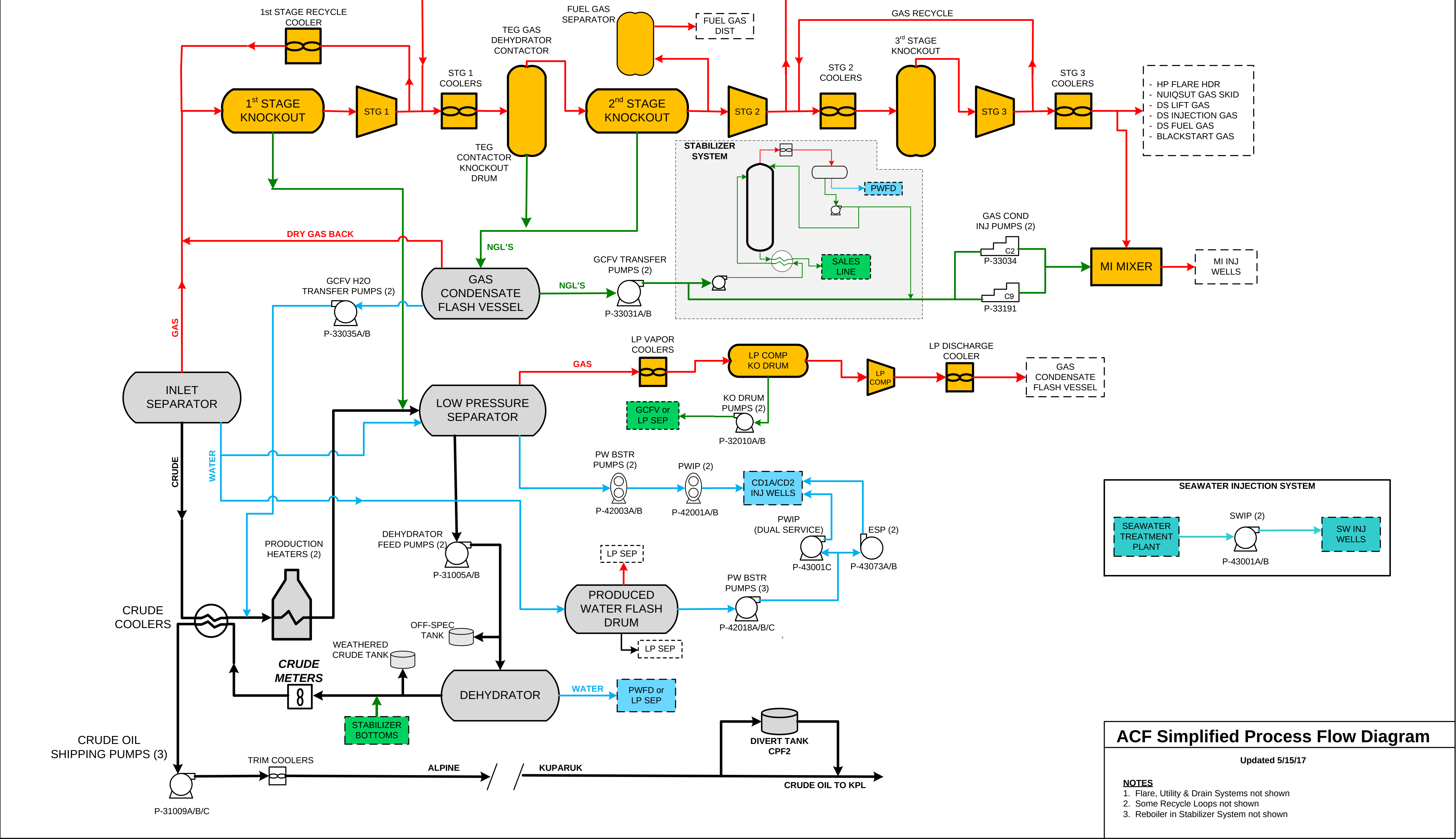


Exhibit 1-6

Alpine Waste Disposal Flow Schematic

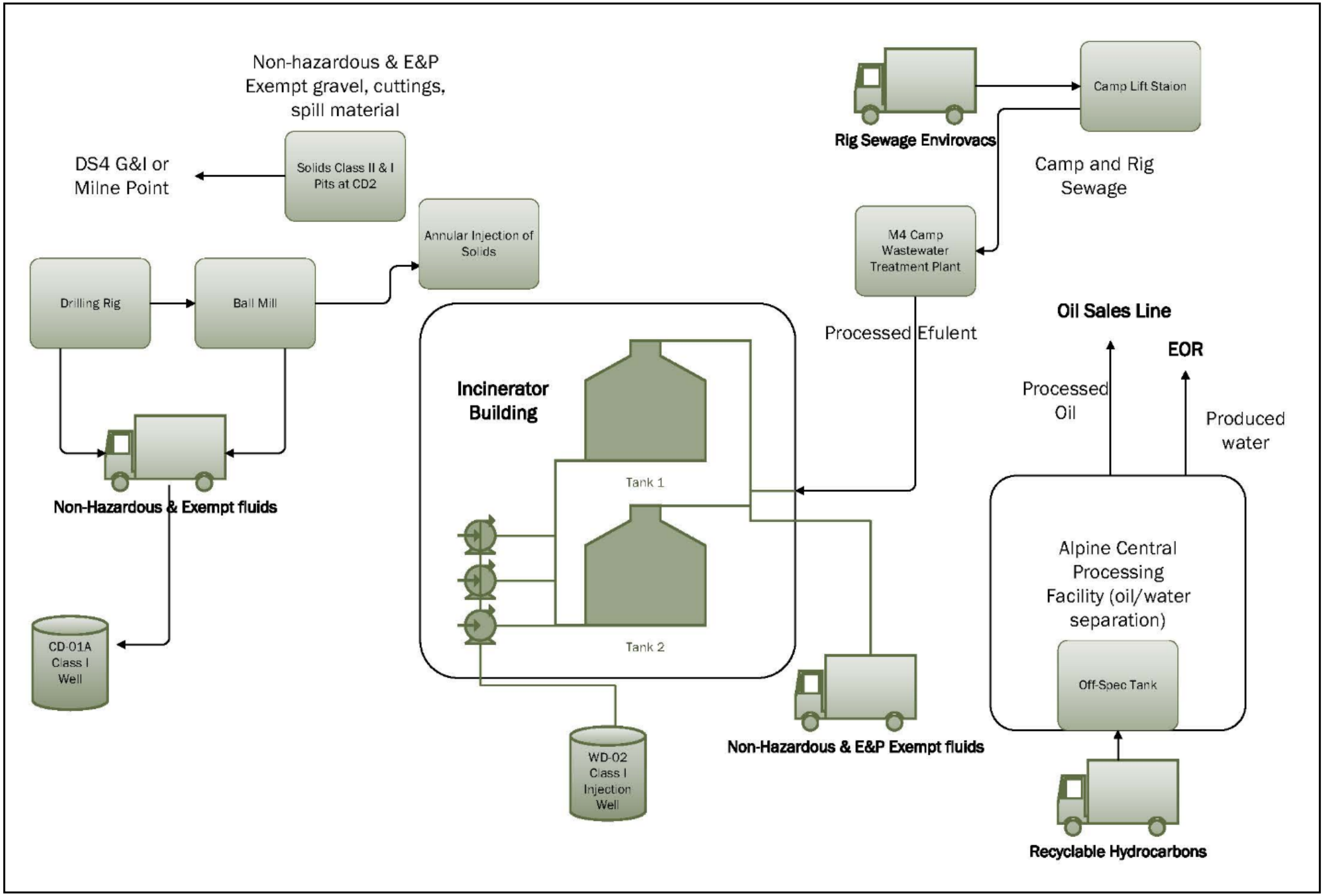
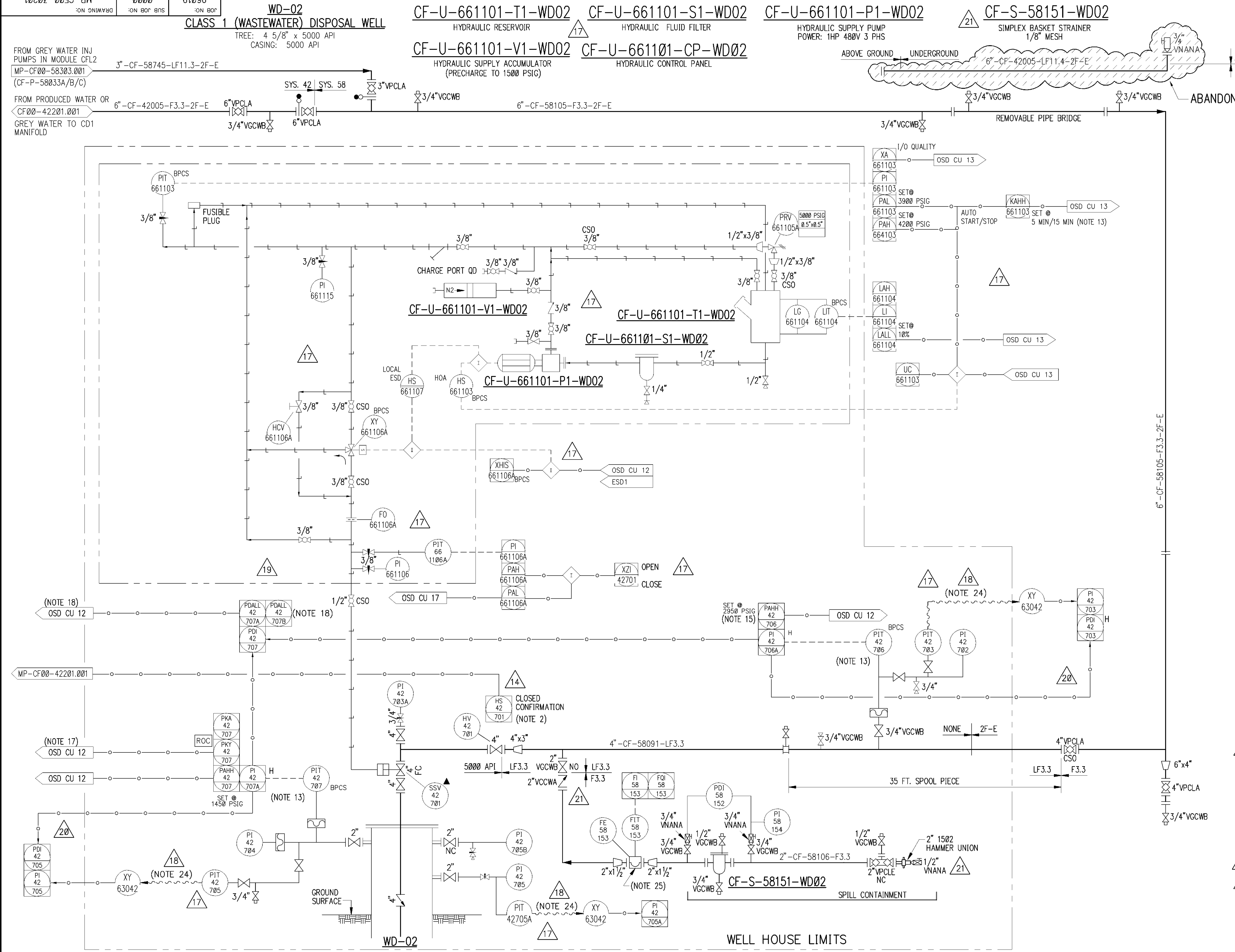
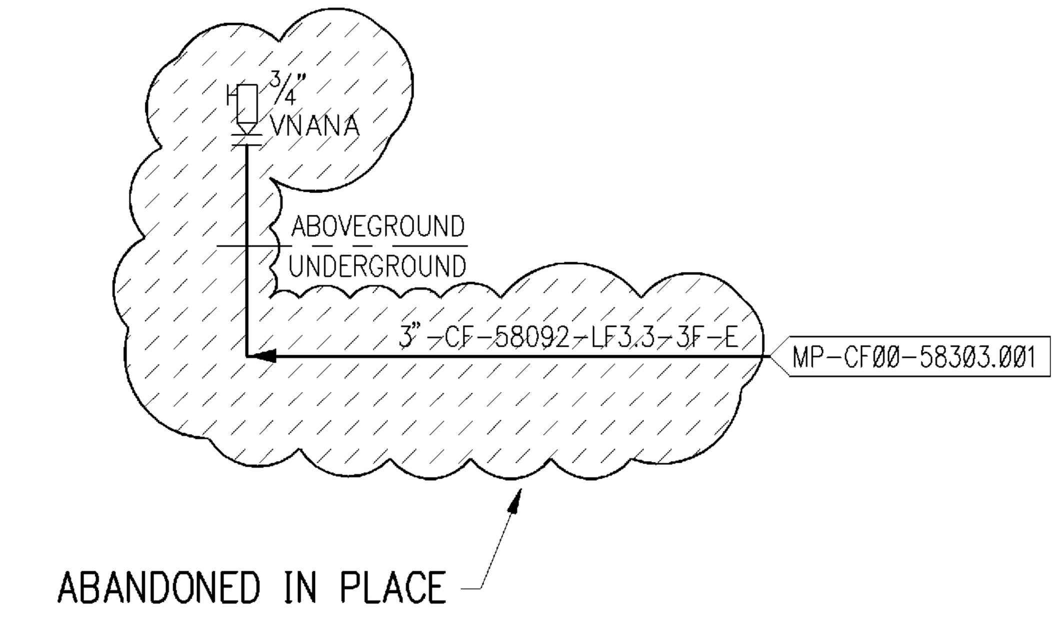


Exhibit 1-7 WD-02 P&ID





NOTES:

1. HEAT TRACE SYSTEM TROUBLE ALARM LOCAL INITIALLY, MONITORED IN DCS LATER.
2. OPERATIONS TO CONFIRM MANUAL BLOCK VALVE IS CLOSED.
3. DELETED
4. BLIND CLOSED UNTIL PRODUCED WATER LINE IS INSTALLED.
5. DELETED.
6. DELETED
7. HEAT TRACE CONTROL PROVIDED BY HEAT TRACE VENDOR CONTROLLER IS SET SO THAT HEAT TRACE IS PERMANENTLY ON.
8. REMOTE HAND OPERATED SSV ACTUATION SWITCH. LOCATE OUTSIDE WELLHEAD SHELTER.
9. FUSIBLE PLUG (SET @ 210°F) WITH EQUIPMENT.
10. HYDRAULIC ACCUMULATOR ACCOMODATES HYDRAULIC FLUID VOLUME CHANGES DUE TO AMBIENT TEMPERATURE RANGE.
11. DELETED.
12. DELETED.
13. REQUIRED REAL TIME HISTORIC DATA RECORDED ON BPCS.
14. DELETED.
15. THE MAX ALLOWABLE WELLHEAD PRESSURE IS 2950 PSIG AS ESTABLISHED BY PAHH-42706 AND THE MAXIMUM ALLOWABLE ANNULUS PRESSURE IS 1450 PSIG AS ESTABLISHED BY PAHH-42707.
16. DELETED.
17. OSD THE SSV, ROV AND INJECTION PUMPS WHEN THE ANNULUS PRESSURE CHANGES MORE THAN 600 PSI IN 1 HOUR.
18. OSD THE SSV, ROV AND INJECTION PUMPS WHEN THE ANNULUS PRESSURE TRACKS WITHIN 50 PSI OF THE TUBING FOR MORE THAN 2 HOURS. PDALL-42707B ALARMS AT 1½ HOURS. (19)
19. DELETED
20. DELETED
21. OSD-CU12 WILL BE BYPASSED WHEN CD1 IS SELECTED AS GWI TARGET.
22. CAPPED TUBING CONNECTIONS PROVIDED ON EACH SIDE OF THE PUMP FOR EMERGENCY HAND PUMP CONNECTION.
23. LOCATE MOMENTARY CONTACT PUMP SWITCH IN LOCATION WHERE PI 42701 CAN BE OBSERVED WHILE OPERATING THE PUMP.
24. (18) WIRELESS SIGNAL TO BASE XY-63042 LOCATED IN E3 JANITOR'S CLOSET.
25. (21) 1 1/2" 2500# METER FLANGE RATING (FE-58153).

REFERENCE DWG NO/SHT NO:

REV	DATE	REVISIONS	BY	CHK	JOB ENGR	PROJ ENGR	CUST APP
17	11 OCT 02	REVISED PER 8097088AEI	COZ	ABC		HF/TN	
16	10 NOV 14	REVISED PER K100001A01	COZ	ABC		TT/JW	
21	14 MAR 08	REVISED PER 9067995AMP	COZ	ABC	–	KH/ES	–
20	06/13	REVISED PER 9527020AEI	CBB	ABC		BD/DF	
19	12 NOV 10	REVISED PER 9038476AEI K120001A01	COZ	ABC		TT/JW	
18	11 NOV 13	REVISED PER 8079937AEI	COZ	ABC		DF/HF	

ECM NO: 71039401M
CC NO: 998791
CADD FILE NO.
SCALE: NTS
DATE: 99 JAN 12

ConocoPhillips Alaska, Inc.

DRAWN: LWM
DESIGN: DD
CHECKED: DHB
REDRAWN FROM: 96019-6-DG-MP-30201.01
APPROVAL: BR

MODULES DEPICTED: WD-02 (WELLHEAD SHELTER)
FORM: D5IZEPID
ALPINE
MODULE: CF00
UNIT: CF
MECHANICAL
P & I D
WASTEWATER DISPOSAL WELL WD-02

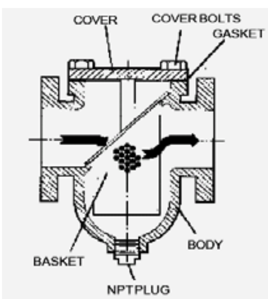
JOB NO:	SUB JOB NO:	DRAWING NO.	PART:	REV:
96019	0000	MP-CF00-30201	001 of 1	21

JOB NO: 96019
SUB JOB NO: 0000
DRAWING NO: MP-CF00-30201

GENERAL DESCRIPTION

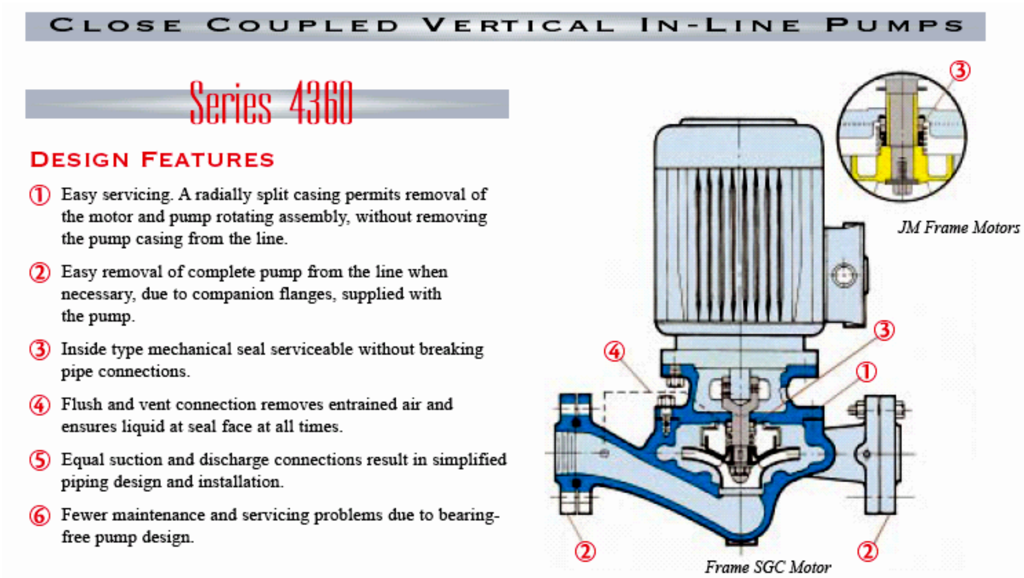
The gray water injection pumps (CF-P-58033A/B/C) inject gray water from the M4 waste water treatment plant into the Class 1 disposal well (WD-02), or into the CD1 produced water injection header. The pumps are in module L2, at the north end of the production facility.

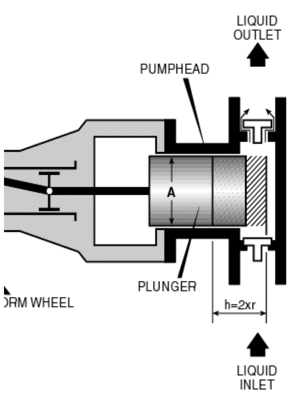
Gray water from the storage tanks is routed through strainers to the gray water booster pump then flows through another basket strainer to the injection pumps. A basket strainer (CF-S-58725 A/B) located on the 6” outlet line from each tank is provided to prevent damage to the booster pump (CF-P-58780). The booster pump supplies liquid through another basket strainer (CF-S-58722) located on the suction line to the injection pumps. This strainer prevents damage to the pump internals which can be caused by solids in the suction.



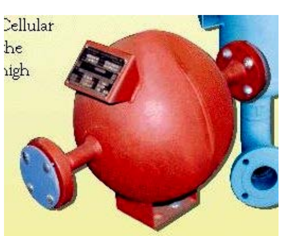
The basket strainers on the tank outlet line are equipped with 1/8” mesh baskets. The injection pumps basket strainer mesh size is 1/16”. Having a dedicated strainer for each tank allows system to continue operating when cleaning a strainer.

The booster pump is a close coupled vertical in line pump manufactured by Armstrong. The pump features positive sealing by proven inside-type mechanical seal. Radially split volute permits removal of the motor and pump rotating assembly without removing the pump volute from the line. Fewer maintenance and servicing problems due to bearing-free pump design.

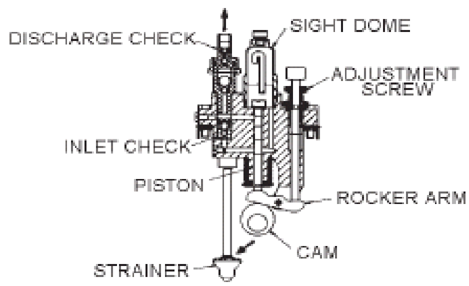




The injection pumps are 50 HP triplex positive displacement pumps coupled to electric drivers through a gearbox. In a reciprocating pump, a specified amount of liquid is taken into the pump through the inlet valves and then totally displaced from the pumping chamber by the piston [plungers] through discharge valves. This reciprocating action generates flow only. Pressure is created by the restriction to this flow after it leaves the pump]. The pistons [plungers] are connected to a crankshaft. The revolutions of the crankshaft [RPM] regulate the displacement of liquid from the pump. The total pump output is in direct proportion to the increase or decrease in RPM. Larger pistons [plungers] permit a greater volume of liquid through the pump. Changes in RPM fine tune the ultimate flow of the pump.



The pump is supplied with a suction stabilizer and discharge pulsation dampener to smooth flow and pressure swings. Positive displacement pumps must control the pulsations resulting from the pump's stroking action. A suction dampener, installed close to the pump inlet reduces the potential for cavitation, extends the pump life, and reduces wear on the manifold and suction valves. A discharge dampener will attenuate pump generated pressure pulsations. This will decrease mechanical vibration and noise. Pressure pulsation shakes pipes and hardens butt welds, particularly when resonance occurs causing fracture that results in spills. Pulsation causes the gaskets between flanges, and seals to migrate, uncontrollable floods and contamination often happen.



One injection pump is normally operated as lead, and a second as lag. The third pump will automatically start/stop at operator defined setpoints. The three pumps are in a parallel configuration and are controlled by local START/STOP/AUTO switches.

Frame lubrication is provided by a gear driven lube oil pump. Rod lubrication is provided by force feed lubricators. Rate for each lubricator should be 10 drops/minute. A 200-gallon tote serves as bulk storage for all pumps. The lubricator level is maintained by LCV-705, 706, 707 for the respective pump. Each pump is shutdown on detection of low level in its lubricator reservoir. The lubricant is SAE 15W40.

The pumps are protected from overpressure due to a blocked line by a PSV located on the 2” discharge line. In addition, a PSV on the suction line prevents overpressure due to check valve leakage.

According to the EPA Class 1 well permit, the maximum allowable surface wellhead pressure is 3200 psig. Redundant pressure switches (PAHH-58722 @ 2950 psig/PAHH-58723 @ 2950 psig/PAHH-58724 @ 2900 psig) mounted on the discharge side of the pumps are set to shut down the pumps at 2900 psig. An additional level of overpressure protection is provided by a pressure switch (PAHH-42706) set @ 2950 psig located at the well to shut in the SSV and stop the injection pumps.

The discharge from the gray water injection pumps can also be directed to the CD1 produced water injection header, by closing the wing valve for the WD-02 Class 1 disposal well, and opening XV-40201 and XV-40202 to create a flow path to the CD1 produced water injection header. The board operator must confirm the wing valve is closed in IP21 before the interlock can be defeated to allow both XV's to be open at the same time.

NOTE: There isn't a stipulation in Area Injection Order (AIO) 18A.01 regarding limiting the camp effluent to 1%, but there is a stipulation that the Operator "must continue to collect and analyze representative samples of the mixed fluid stream to demonstrate its continued suitability for EOR injection." After many years of more aggressive sampling, an annual sample now satisfies this requirement. The analyses must be retained and available by request of AOGCC for 5 years. Well injectivity is another way to demonstrate that the water is suitable.

Diverting water normally injected in WD-O2 into the Alpine Oil Pool complies with AIO 18.01A.

WNS pools (Qannik, Fiord, and Nanuq) authorize injection of the treated camp effluent without restriction on volume.

Approved fluids to inject into Nanuq include: seawater, commingled produced water, enriched gas, and miscellaneous sump fluids, hydrotest fluids (excluding fluids from tests of transportation pipelines), rinsate from washing mud trucks, excess well work fluids, treated camp effluent and mixtures of same.

AIO 18A.01A also requires that volumes be incorporated into monthly and annual injection reports on standard AOGCC forms (10-406 & 10-413). These forms have specific instructions regarding the reporting injectant type and method. Injectant type is "Liquid (bbl)" or "Gas (MCF)", and WNS methods are "Water Injection", "Miscible Injection (WAG)", or "Gas Injection".

Two chemical Injection pumps (CF-P-50041 / CF-P-50043) have been installed to treat the gray water. CF-P-50041 is set up to pump biocide to the suction header of the gray water injection pumps. This pump is runs 2 consecutive hours once a week when an injection pump is on line. CF-P-50043 is set up to pump corrosion inhibitor to the suction header of the gray water injection pumps. This pump will start up automatically whenever the gray water injection pumps start, and will automatically adjust the chemical rate based on the number of gray water injection pumps running.

Gray water pumps ON / OFF set points are set by the Alpine board operator through IP21.

DESCRIPTION AND ENGINEERING SPECIFICATIONS

GENERAL DESCRIPTION

Gray water is pumped from AOC M1 treatment plant via a 3" pipeline into the gray water storage tanks (CF-T-58701A/B) located in module L2. The tanks are fiberglass and resin which do not corrode. The tanks provide a surge volume for storage of effluent water prior to injection. The outlet of each tank is equipped with a basket strainer with 1/8" mesh to protect the downstream pumps. On the east side of L2 is a truck connection for offloading gray water to the tanks. A basket strainer (CF-S-58723) is located in the off-loading line to prevent the transfer of solids to the tank.

An indication of tank level is provided by level indicators (LI-58701A/LI-58703A) send a signal to a 24-hour manned station. A high high level in the tank is indicated by level switches (LSHH-58702/LSHH-58704), (LAHH-58702/LAHH-58704) and signal the valve (ROV-58702) on the inlet header to close. Each tank has an overflow line which dumps inside the module. Low low level is indicated by level switches (LI-58701A/LI-58703A) that activate local alarms and (LALL-58701/LALL-58703) shut down the downstream injection pumps.

The tanks operate at atmospheric pressure. Both the overflow line and the 6" tank vent are relief paths. PSV-58701A/B provide additional pressure protection

Tank temperature indicators are located on each tank.

2.0 WASTE SOURCES AND CHARACTERISTICS

2.1 Introduction

The majority of wastes generated by oil and gas exploration and production are exempt from the Resource Conservation and Recovery Act (RCRA) Subtitle C Regulations. These wastes include drilling muds and cuttings, produced water not usable for enhanced oil/gas recovery (EOR), and a class of waste termed "other associated waste”.

Drilling muds are usually water-based mixtures of clays and weighting materials with small amounts of various additives; however, oil-based mud may be used in special drilling applications and will be used in the lower part of some development wells. Produced water that comes to the surface mixed with the oil and gas is reinjected (reused) for reservoir pressure maintenance.

Other associated wastes specifically include waste materials intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil and natural gas. "Intrinsically derived from primary field operations" is intended to distinguish exploration, development, and production wastes from wastes derived from transportation and manufacturing. In general, the exempt status of an exploration and production waste depends upon how the material was used or generated as outlined in the EPA guidance booklet, "Crude Oil and Natural Gas Exploration and Production Wastes: Exemption from RCRA Subtitle C Regulation".

In addition to the three major classes of exempt waste, field operations create some nonexempt, non-hazardous wastes and a small volume of hazardous waste, typically from equipment and building maintenance. Wastes not intrinsically associated with the production of oil and gas are not exempt wastes and are regulated under Subtitle C of RCRA if they are hazardous. Hazardous wastes are periodically shipped off-site to regulated disposal facilities.

2.2 Sources and Volumes of Wastes

Exhibit 2-1 lists examples of wastes that could be disposed of via injection into the existing Class I well (WD-02). The exhibit also includes a brief description of each waste. The monitoring and routing of the wastes to the proper disposal well is controlled by the Alpine Waste Analysis Plan (WAP) (see Appendix A) and by the North Slope Alaska Waste Disposal Reuse Guide-Revision 10 (May 2015) (“Red Book”). Both documents are updated as operations change. The updated Red Book is available upon request.

The historical table below reflects that the WD-02 well has been used primarily for graywater and produced water disposal. As of January 1, 2018, approximately 6.1 million barrels (MMB) have been injected into WD-02.

Historical WD-02 Class I Waste Disposal at Alpine (as of 1/1/2018)

Well WD-02	Volume Injected (barrels)	Historical %
Domestic Wastewater/Graywater	5,575,492	91.4%
Produced Water	361,830	5.9%
Other Non Exempt Non Hazardous Fluids	159,426	2.6%
Drilling Fluids and Drill Cuttings	1,991	<1%
Wellwork Fluids	1,357	<1%
TOTAL	**6,100,096**	**100%**

Forecasted WD-02 Class I Waste Disposal Volumes
(20 Years Remaining Life)

Liquids	Forecasted Injection Volumes (barrels) 2018 through 2038	Forecast %
Domestic Wastewater/Graywater	6,633,094	95%
Produced Water	139,644	2%
Other Non-Exempt Non-Hazardous Fluids	69,822	1%
Drilling Fluids and Drill Cuttings	69,822	1%
Wellwork Fluids	69,822	1%
TOTAL	**6,982,204**	**100%**

2.3 Typical Injection Stream for WD-02

Class I well WD-02 receives metered graywater from the Alpine Wastewater Treatment Plant via two storage tanks. Booster and injection pumps take fluid from the storage tanks and pressure it up for injection into the well. Tie-in points downstream of the injection pumps allow for fluids to be injected into WD-02 from a truck offload station and from the facility produced water pumps. The WD-02 booster and injection pumps run intermittently throughout the day.

2.4 Class I Waste Disposal Options (Other than injection at WD-02)

<u>Class I Camp Wastewater Treatment Plant Effluent:</u>
The options for disposal of this waste stream include subsurface injection at CD1-01A, or beneficial reuse in the EOR injection system as approved by the Alaska Oil and Gas Conservation Commission (AOGCC).

Other Class I Liquids (Bulk):
These non-exempt fluids can be hauled to other North Slope Class I wells if there is an ice road, which is limited to a short period each year.

Class I Liquids in Barrels, (non-hazardous):
Given Alpine's limited footprint, surrounded by tundra, and only seasonal ice road connection, large scale drum storage is not practicable. Additionally, it would create an additional waste stream (used drums) and increased environmental risk associated with handling.

Class I Solids:
This volume should be small, primarily the result of non-exempt fluids spilled on pad surfaces. It may be hauled to other Class I disposal sites when there is an ice road. Alternately, it would have to be stored prior to disposal. If hazardous, it would be transported to a permitted treatment, storage, or disposal facility.

2.5 Handling and Analysis of Wastes

The Alpine Waste Analysis Plan (WAP) is included in Appendix A. Also, the North Slope "Red Book" guidelines will be used as has been done in the past.

Non-hazardous fluid determinations will be made based on laboratory data, material safety data sheets, and generator knowledge. Documented generator knowledge of a waste may be substituted for analytical data according to 40 CFR 262.11 (c)(2), and therefore sampling and analysis may not be necessary for the following items:

- RCRA exempt oil-gas wastes.
- Known non-hazardous industrial wastes as described in the WAP.
- Wastewater streams including sanitary and domestic wastewater.
- Desalination plant by-product effluent.

2.6 Waste Generating Areas

Approved waste streams generated outside of the CRU (e.g. GMTU), including CPAI or third-party wastes generated at other North Slope locations, will be accepted for disposal under certain circumstances. All third-party generators must evaluate their wastes in accordance with a WAP approved by Alpine Operators, and adhere to Red Book procedures including use of the North Slope Manifest. A third-party WAP must list the general procedures and record keeping requirements to be adhered to before the third-party generators can have trucks unloaded.

CPAI believes the operational procedures, manifest system, and the WAP are sufficient for ensuring proper waste handling. Trained onsite foremen, operators, and a supervisory staff provide oversight for compliance.

EXHIBIT 2-1
WASTE STREAMS DESCRIBED IN PERMIT APPLICATION

The following wastes were identified on Alpine's UIC application or are documented as changes in the "record of revisions" table.
For this exhibit, they have been re-arranged in alphabetical order and edited for brevity.

Waste	General Description ***Note:*** *Wastes on this list* ***are not*** *automatically approved for injection. Each must be evaluated for disposal in accordance with Section 2 of the Waste Analysis Plan*.
Acid	Used widely as cleaning fluid in well work and chemical process. Low pH.
Arctic pack	A proprietary product, consisting of diesel with some gel additives. Used to prevent freezing of well facilities, which are exposed to cold weather. Becomes a waste as a result of contamination by water, soil, or hydrocarbons, or as a result of a well workover.
Boiler blowdown water	Fresh water used in boilers, typically to make steam for drilling rigs. It is collected when the boiler is taken out of service.
Caustic fluid	A wide range of high-pH materials normally generated by cleaning operations, as off-specification chemical compounds, or as the result of chemical combinations.
Clean-up fluids (washwaters)	Predominantly water which has been contaminated in the process of washing down an area, engine, etc.
Contaminated gravel	Result of spills associated with various oil field operations.
Crude oil	Generated as waste from a well workover or from spills. A blend of many types of hydrocarbons with some impurities. May be contaminated with water and soil.
Diesel	Diesel wastes may be generated as contaminated fuel, solvent, workover fluid, or freeze protection fluid. May be contaminated with small amounts of chemicals or water.
Grey Water (domestic wastewater)	Originally potable water; comes from the kitchen, showers, lavatories, laundry, toilets, and any camp floor drains.
Drill cuttings	Generated when the drill bit penetrates the rock formation. Circulated to the surface with the drilling mud and are mechanically separated from the liquid mud. Can be composed of sand, gravel, clay, shale, hydrocarbon bearing rock, or other naturally occurring formation solids.
Drilling muds, oil-based	Used for cooling and for the flushing of cuttings during well drilling. Typically a mixture of a hydrocarbon fluid (usually mineral oil or diesel), clay or asphalt, some water, and dissolved chemicals, which enhance certain properties of the mud. The odor is characterized by the hydrocarbon fluid. Returned mud may carry a significant amount of solids (soil and rock fragments).
Drilling muds, water-based	Used for cooling, lubricating the drill bit, and flushing cuttings to the surface. Also used to suspend solids during the grinding and injection disposal process. Consist of water, clay (usually bentonite), and additives such as barium compounds that enhance certain properties. Returned mud may carry a significant amount of solids (soil and rock fragments).

Waste	**General Description** ***Note:*** *Wastes on this list* ***are not*** *automatically approved for injection. Each must be evaluated for disposal in accordance with Section 2 of the Waste Analysis Plan.*
Frac sand	Certain well stimulations utilize proppant or "frac sand" to fill formation fracture spaces created during a well stimulation. An inert ceramic material, and as a waste it is commonly accompanied by crude oil, fresh or sea water, formation solids, small amounts of chemicals and spent acid. Frac sand waste may be found at the wellhead, in production facility separation vessels, and in flow line pigging material.
Glycol	An alcohol that is widely used in circulating fluid systems to prevent freezing. May be contaminated with water, hydrocarbons, or solids.
Incinerator ash	The result of burning paper, wood products, rags, etc. in an incinerator. It can be injected as slurry if testing confirms it is non-hazardous.
Laboratory waste	Various chemicals, products, and contaminants, some of which will be regulated as hazardous waste.
Line Pigging Material	Materials that have built up on the walls of crude oil pipelines and produced water or seawater pipelines. Normally pushed through the pipelines back to the production facilities and deposited in facility vessels, from which it is later removed as vessel sludge/sand. Occasionally pigging waste will be removed directly from pipelines. Can include crude, produced or seawater, biomass, paraffin, formation solids, frac sand, calcium scale, and iron sulfide.
Lubricating oils and hydraulic fluids	Produced as wastes from engines and power transmission systems. Contain small amounts of metal and chemical additives to enhance their properties.
Methanol	Light alcohol used widely as a freeze prevention fluid. May be used in combination with other materials, such as glycol.
Miscellaneous wastes	Includes seawater, surface runoff to well cellars, snowmelt, and fresh water, which is not considered clean-up fluid. May contain small amounts of contaminants.
Natural gas liquids (NGLs)	Petroleum products (propane, butane, etc.) which are disposed of as wastes when they become contaminated with water, solids or some other hydrocarbon. Ignitable.
Naturally occurring radioactive material (NORM)	Weakly radioactive natural material that sometimes forms as pipe scale or sludge in production pipelines, tubing, and separation vessels. The material is typically found as barium sulfate scale with some radium 226 or 228 co-precipitating with barium. Radiation levels of 1 to 2 millirems per hour are below activity levels of concern by the Nuclear Regulatory Commission.
Produced water	Brine produced from the oil reservoir during the oil recovery process, separated from the oil and gas.
Produced solids	Solids produced from oil reservoir during the oil recovery process and may include solids from well flowbacks prior to production.
Production chemicals	Broad category that includes chemicals used in production or transportation of crude to achieve certain desirable effects. Examples include corrosion inhibitors, emulsion breakers, foam suppressants, and proprietary compounds used in drilling fluids, muds, and cleaning products.
Production facility fluids	Broad category that includes chemicals not used to treat or process produced fluids. Examples include fire water, H2S or oxygen scavenger, MEG, non-process water from various sources, and chemicals from bulk storage
Solvents	A wide range of products that may be contaminated with grease, solids, and/or water. All solvents must be carefully evaluated for disposal options - only those classified as non-hazardous will be accepted for disposal.

Waste	**General Description** ***Note:*** *Wastes on this list* ***are not*** *automatically approved for injection. Each must be evaluated for disposal in accordance with Section 2 of the Waste Analysis Plan*.
Source water	(Not planned for use at Alpine at this time.) Subsurface water produced from saline aquifers below the permafrost. Potentially used for making drilling mud and flushing the disposal well.
Stimulation fluids	Chemical compounds which are injected into producing or injector zones to enhance the productivity or injectivity of a well. May contain various chemicals to enhance its properties.
Transformer oil (no PCBs)	Used as a non-conducting medium in electrical power transformers. Discarded when the equipment is abandoned.
Vessel sludge/sand	Fine solid particles from the oil producing formation, biomass, pipe scale, or frac sand. Can accumulate in test separators, tanks, production facility vessels, and heat exchangers. These solids are periodically removed and can be associated with crude oil, fresh or seawater, and production chemicals or solvents.
Workover fluids	Wastes from the maintenance of a hydrocarbon production well. Predominantly water; may contain small amounts of chemicals, crude oil and solids.

3.0 GEOLOGIC SETTING

3.1 Geology and Lithology

The geology of Permo-Triassic and Jurassic age sediments within the Alpine Field is described, with specific reference to the injection and confining intervals in the Class I wells. Exhibit 3-1 shows the Lower Cretaceous through Permo-Triassic formations and horizons penetrated by Class 1 disposal well WD-02. The intervals of interest comprise sedimentary rocks of the Kingak, Sag River, Shublik, Ivishak, and Kavik Formations. These intervals are continuous over most of the CRU based on regional well correlations and seismic. A seismic section through CD1-01A and WD-02 is presented in Exhibit 3-2. Structure maps on the top of the injection zone and top of the confining zone are shown in Exhibits 3-3 and 3-4, with the locations of the disposal wells noted.

The Jurassic and Permo-Triassic sediments are part of the Ellesmerian sequence characterized by marine transgressive-regressive cycles deposited on a slowly-subsiding passive-margin ramp to the south with a broad, stable platform to the north. The Permo-Triassic Ivishak formation consists of lowstand fluvial-deltaic-marginal marine deposits that accumulated along the south-facing Ellesmerian ramp. Triassic transgression blanketed this interval with an organic-rich calcareous shale (Shublik Formation) and shelf sandstone (Sag River Formation) across the tectonically stable northern platform. The overlying Jurassic section (Kingak Formation) consists of southward prograding marine clastics.

The Ivishak Formation is approximately 700 feet thick and consists mostly of quartz-rich sandstone with thin shale interbeds. The sandstone is well consolidated, fine to medium grained, moderately sorted with thin conglomeritic intervals.

Formation Nomenclature

Age	Formation	Depositional Environmental and Lithology
Jurassic	Kingak	Marine shelf and prodelta shales
Triassic	Sag River	Shallow marine sandstones
Triassic	Shublik	Shallow to deep marine limestones, sandstones and shales
Permian/Triassic	Ivishak	Fluvio-deltaic sandstones, conglomerates, and siltstones, and shaless
Permian	Kavik	Prodelta and shelf shales

Geology of the Waste Disposal Zones

The geologic subdivisions for the confining and injection zones are shown on the WD-02 log (Exhibit 3-1) and on the seismic cross section (Exhibit 3-2). In addition to WD-02, CD1 pad wells CD1-01A and CD1-19A have complete log suites down to the Permo-Triassic Ivishak Formation.

The table below summarizes the formation and injection and confining zones displayed in the exhibits. The stratigraphic nomenclature used here is the same as used in the Prudhoe Bay and Kuparuk Fields.

Age	Formation	Injection & Confining Zones
Jurassic	Kingak	Upper Confining Zone
Triassic	Sag River	Upper Injection Zone
Triassic	Shublik	Barrier
Permian	Ivishak	Lower Injection Zone
Permian	Kavik	Lower Confining Zone

3.2 Injection and Confining Zones

Upper Confining Zone

Jurassic Kingak Formation: The Kingak confining zone is comprised of approximately 1500’ of shale, siltstone, and low porosity sandstone. The lowermost 700’ of the Kingak above the Sag River sandstone is a shale prone interval found in all CRU wells which penetrate the entire Jurassic sequence. The shales were deposited in a marine shelf environment with increasing clastic input towards the top of the sequence.

Upper Injection Zone

Triassic Sag River Formation: The upper injection zone is the Sag River Formation which contains approximately 40 feet of gross sand thickness. The Sag River sandstone consist of fine-grained, glauconitic sandstones interpreted as lower shoreface/shallow marine shelf deposits. The Sag River has good reservoir properties with an average permeability of 120 millidarcies.

Barrier Between Injection Zones

Triassic Shublik Formation: Between the two proposed injection zones, there are approximately 400 feet of shale, siltstones, and limestones deposited during a Triassic marine transgression. The base of the barrier or Lower Shublik Formation consists predominantly of siltstones and shale. This section is overlain by the high resistivity limestones of the Upper Shublik Formation. The limestones are interpreted to be deposited in a shallow marine environment during a period of quiescence with minimal clastic input. The Shublik is characterized by low porosity and permeability.

Lower Injection Zone

Permo-Triassic Ivishak Formation: In the CRU, the Ivishak Formation is 600-700 feet thick and consists of thick-bedded sandstones, thin-bedded conglomerates, and siltstones and mudstones. The Ivishak is interpreted to represent a fluvial-deltaic depositional system. The sandstones are fine-medium grained, well consolidated, and have moderate reservoir quality.

Lower Confining Zone

Permian Kavik Formation: Below the Ivishak Formation is the Kavik Formation, which in the CRU is 200 - 250 feet thick and consists of medium to dark gray, silty shales. The Kavik is interpreted to be deposited as shelfal and pro-deltaic deposits.

Structure

Structure maps for the top of the injection zone (Sag River) and top of the confining zone (Kingak) are included as Exhibits 3-3 and 3-4. These maps were generated from a 3D seismic depth volume that was tied to existing well control. The vertical accuracy of the depth maps is +/- 50 feet as tested by prior drilling results.

The general structure of the Jurassic and Permo-Triassic sequence is west-southwest dip averaging one degree. Extensional northwest-trending faults that cut the Ivishak section generally have throws ranging from 20 - 50 feet and tend to die out within the overlying thick Jurassic shale section. These normal faults are shown on the seismic section (Exhibit 3-2) and Sag River structure map (Exhibit 3-3). None of the mapped faults in the vicinity of the CD1-01A or WD-02 wells extend from the injection zones up through the Kingak Shale confining zone.

Occurrence of Hydrocarbons

There are no known hydrocarbon accumulations within the Permo-Triassic injection intervals in the CRU.

3.3 Subsurface Aquifers

The EPA letter confirming that the Alpine Field is in a No Underground Sources of Drinking Water (USDW) Area is included in Exhibit 3-5. Also, the permit fact sheet documents EPA's ruling that there are no underground sources of drinking water within the Alpine Field. See Exhibit 3-6.

Exhibit 3-1 WD-02 Stratigraphy Type Log

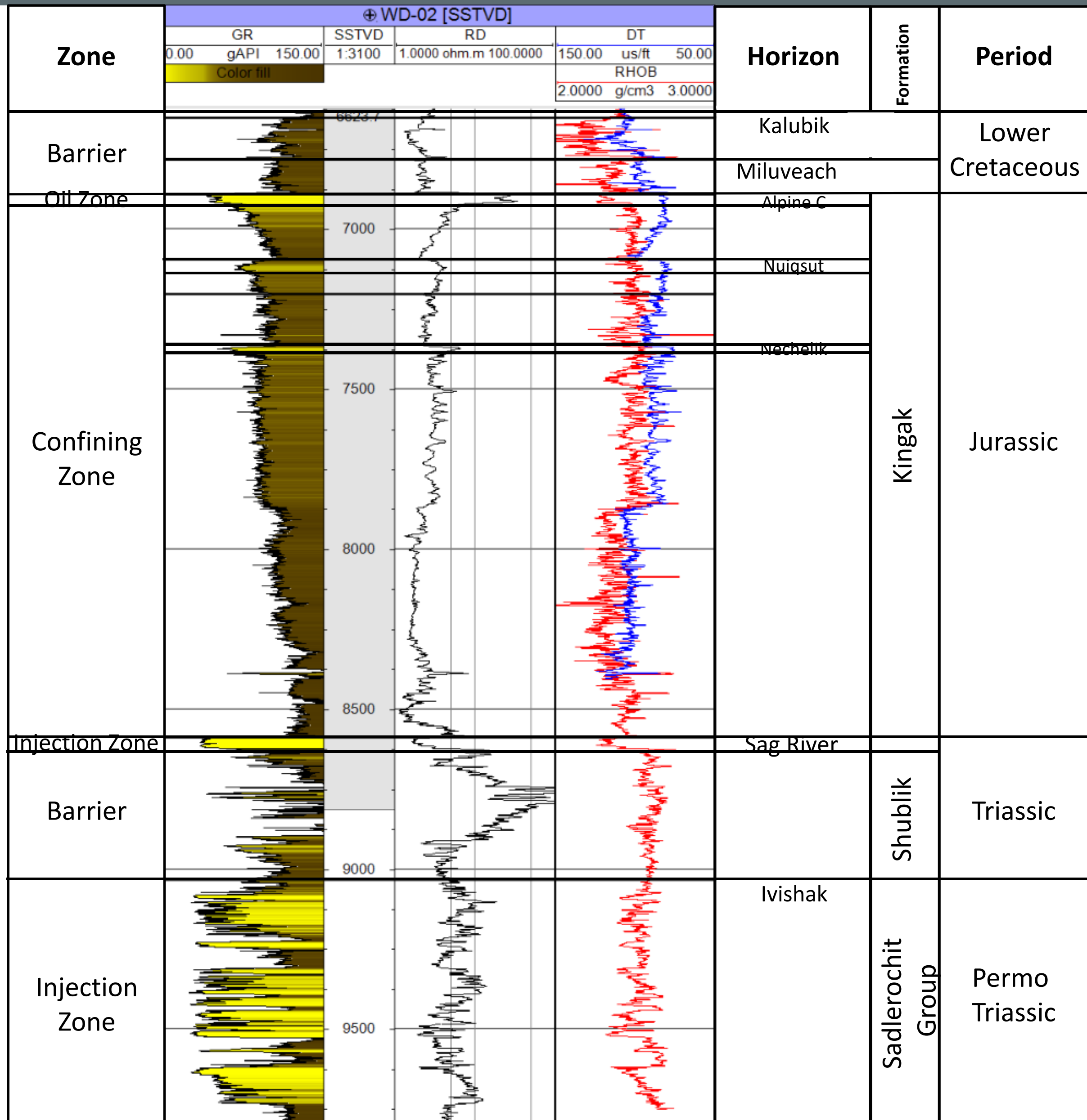


Exhibit 3-2

West-East Seismic Section

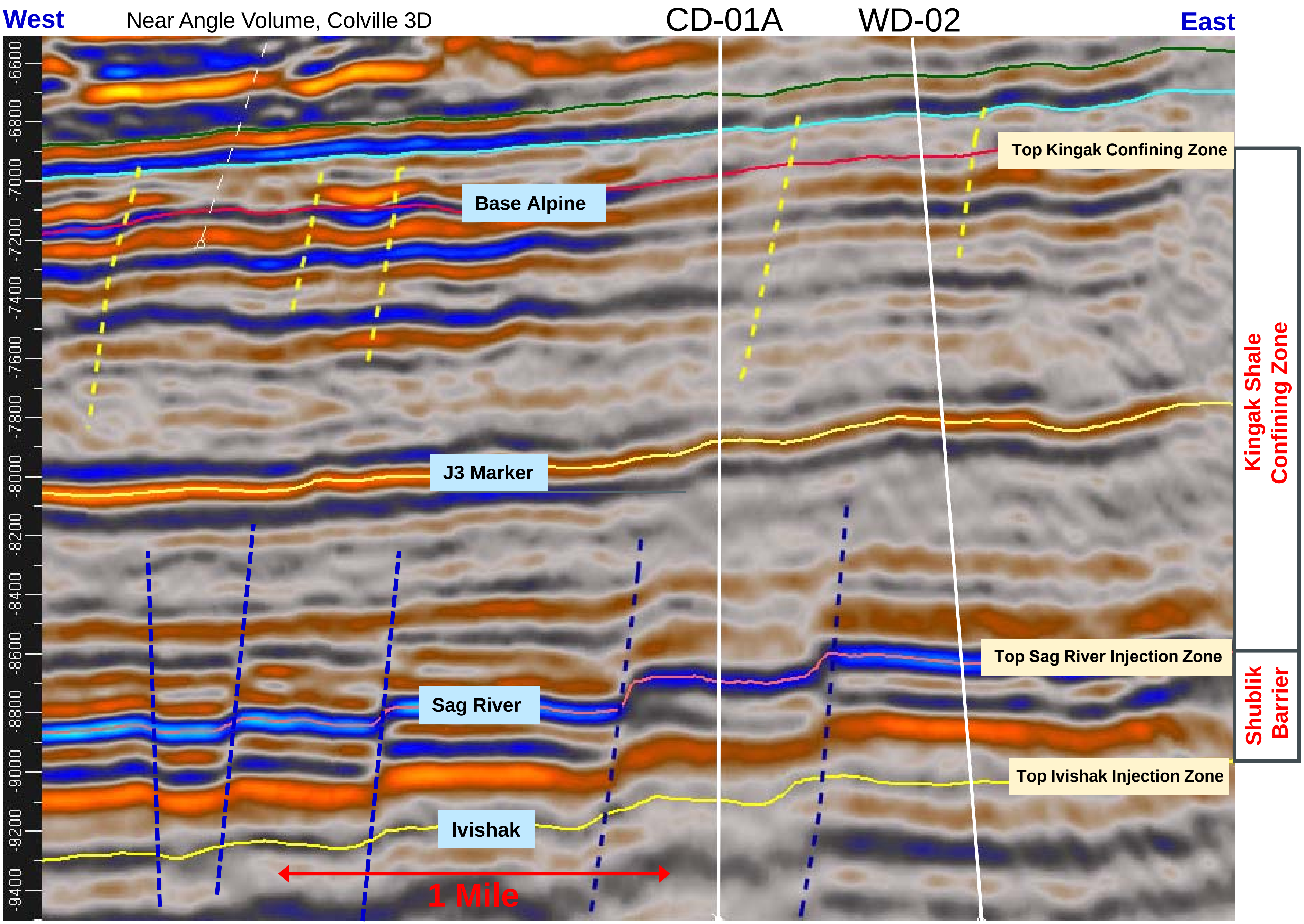


Exhibit 3-3

Top Sag River Depth Structure Map (top injection zone)

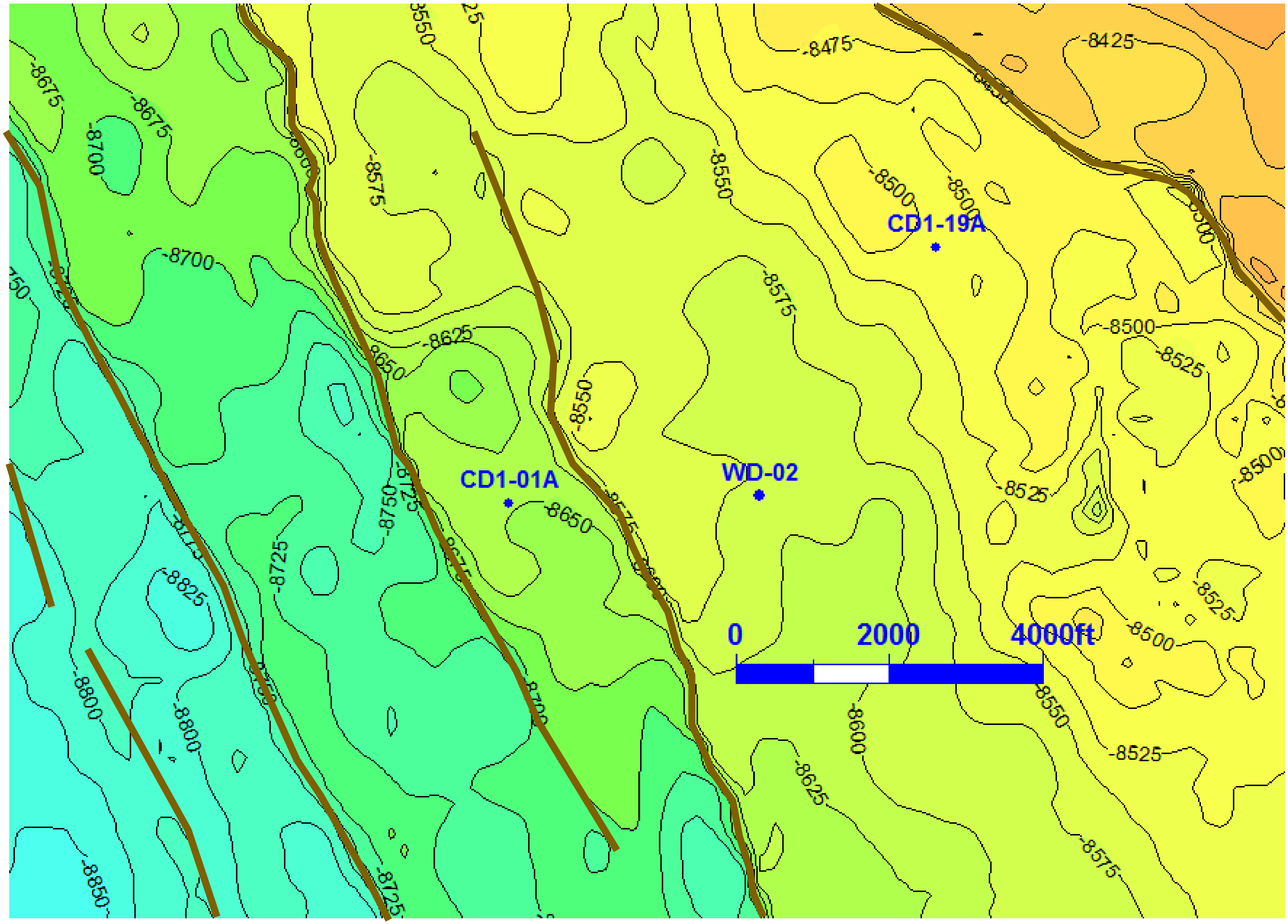
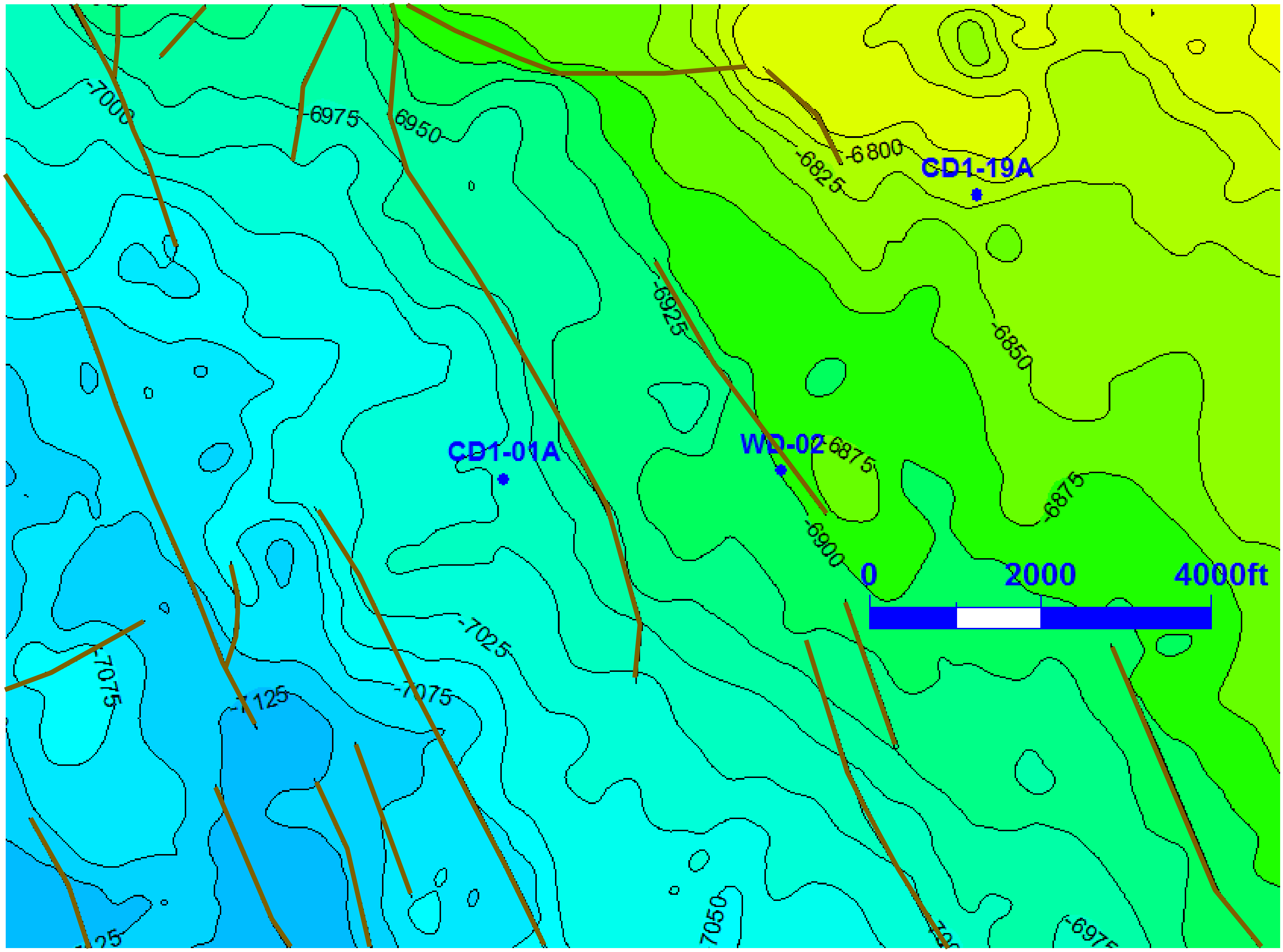


Exhibit 3-4

Top Kingak Depth Structure Map (top confining zone)



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, WA 98101

2 AUG 2007

Reply To
Attn Of: OCE-127

Exhibit 3-5 EPA No USDW Letter

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Jason Charton
ConocoPhillips Alaska, Inc (CPAI)
Senior Environmental Coordinator
700 G Street, ATO 1756
Anchorage, Alaska 99510-0360

Re: EPA Confirmation that CD1-19A is located within a No Underground Sources of Drinking Water (USDW) Area
Well CD1-19A, Alpine Development Project (Alpine), Colville River Unit, North Slope, Alaska.

Dear Mr. Charton:

The U.S. Environmental Protection Agency (EPA), Region 10, Office of Compliance and Enforcement, has received CPAI's letter dated July 23, 2007. This letter requested that EPA confirm that Alpine Well CD1-19A is located within a no USDW area, Alpine Field, North Slope, Alaska, and that this field (currently known as the Colville River Field) does not qualify as underground sources of drinking water (USDWs) as defined in 40 CFR§144.3. Based upon a review of the information provided by CPAI, EPA confirms the Alpine Well CD1-19A is located within Alpine Field (Colville River Unit), a no USDW area.

In summary, EPA approved a Class I injection well, WD-02 at Alpine on February 3, 1999, and reviewed documents received in 1998 supporting a no USDW ruling for the Alpine Field at that time. EPA has received and re-reviewed the water sample analyses submitted in 1998 from five wells and the petrophysical data submitted in 1998 from four wells. EPA has also received and reviewed additional petrophysical data submitted July 23, 2007, from Alpine Well CD1-19A that confirms salinities are in excess of 11,100 milligrams per liter (mg/l) TDS. Based on the review, EPA concurs with CPAI the aquifers in Alpine Field exhibit total dissolved solids concentrations that significantly exceed the 10,000 milligrams per liter (mg/l) TDS threshold for a USDW, and Alpine Well CD1-19A is located within Alpine Field, a no USDW area.

If you have any questions or need clarification, please contact Mr. Thor Cutler of my staff at (206) 553-1673.

Sincerely,

Michael A. Bussell, Director
Office of Compliance and Enforcement

cc: James Regg, AOGCC, Anchorage, AK

Exhibit 3-6 - EPA UIC Well Fact Sheet.

FACT SHEET

Proposed Issuance of Underground Injection Control (UIC) Area Permit AK-1I003-A for the Construction and Operation of Class I Non-Hazardous Industrial Waste Injection Wells at the Alpine Oil and Gas Development of the Colville River Unit on the North Slope of Alaska

U.S. Environmental Protection Agency, Region 10
Ground Water Protection Unit, OW-137
1200 Sixth Avenue
Seattle, Washington 98101

December 18, 1998

Introduction

ARCO Alaska, Inc. has submitted an Underground Injection Control (UIC) permit application for the construction and operation of up to three Class I non-hazardous industrial waste injection wells at the Alpine Field in the Colville River Unit on the North Slope of Alaska. The application was submitted to EPA on September 3, 1997, and additional information was sent to EPA on August 4, 1998. In response, EPA has prepared a draft permit for public review and comment. The public comment period will remain open until January 19, 1999, as described later in this fact sheet.

The 10-year term EPA permit would allow ARCO to inject all of the non-hazardous waste fluids generated at the Alpine Field into the naturally saline Ivishak and Sag River Formations at depths of about 8500 to 9500 feet below the land surface. This plan to inject non-hazardous waste fluids generated at Alpine is favored by EPA since it will minimize discharge to the land surface and surface water bodies, and will reduce the need to transport waste from this isolated field (located about 25 miles west of the Prudhoe Bay all-weather road network) to off-site treatment or disposal.

Public Comment

Peer review comments were sought from the Alaska Department of Environmental Conservation (ADEC) and the Alaska Oil and Gas Conservation Commission (AOGCC) in the development of the draft permit and this fact sheet. EPA is now requesting public comment prior to issuing the permit. Persons wishing to comment on the draft permit may do so in writing by January 19, 1999. All comments should include the name, address, and telephone number of the person making comment, a concise statement of the exact basis of any comment, and the relevant facts upon which it is based. All written comments and requests should be submitted to EPA at the above address to the Manager of the Ground Water Protection Unit or via electronic mail to partee.grover@epa.gov . After January 19, 1999, EPA may finalize the permit as drafted if no substantive comments are received during the public notice period.

Regulatory Framework

The Underground Injection Control (UIC) program is authorized by Part C of the Safe Drinking Water Act for the principal purpose of protecting Underground Sources of Drinking Water (USDWs) from contamination by injection through wells. The UIC regulations (see 40 CFR 144.3) broadly define USDWs as any aquifer capable of supplying a public water system with water of less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS).

Primary responsibility for regulation of injection wells through the UIC program is split in Alaska between EPA and the Alaska Oil and Gas Conservation Commission (AOGCC). The AOGCC has UIC program primacy for the regulation of Class II wells, and EPA directly regulates the other four classes of injection wells in Alaska. Class II wells are defined (see 40 CFR 144.6) as those wells used for injection in order to: 1) dispose of fluids brought to the surface from oil and gas production operations, 2) enhance the recovery of oil or natural gas, or 3) store liquid hydrocarbons underground. Class I non-hazardous industrial waste wells may be used to inject fluids eligible for Class II injection and any other non-hazardous waste. Therefore, ARCO is seeking to obtain a Class I non-hazardous waste injection well permit from EPA in order to inject all non-hazardous waste fluids generated at the site, regardless of whether or not the wastes are brought to the surface as part of the oil production process.

Underground injection needs to be conducted in a manner which ensures the protection of USDWs. However, based upon available information, EPA has determined that there are most likely not any aquifers beneath the permafrost in the Alpine field area which are fresh enough (less than 10,000 mg/L TDS) to qualify for protection as USDWs. Under these circumstances, the Director may authorize injection with less stringent requirements than would otherwise be required (see 40 CFR 144.16). EPA intends to grant several waivers requested by ARCO which are described under the Geologic Setting and Injection Issues portion of this fact sheet.

General Project Overview

The Alpine field area of the Colville River Unit is located about 60 miles west of Deadhorse, Alaska, and about 25 miles west of the westernmost part of the Prudhoe Bay all-weather road network. The isolated oil development will not be served by an all-weather road. ARCO has requested an area permit to allow the drilling, construction, and operation of up to three Class I non-hazardous industrial waste injection wells from the main facilities pad.

ARCO anticipates that the project will have a lifetime of 20 years. During this time, the Class I injection well(s) may be used to dispose of all non-hazardous waste generated at the project site. ARCO estimates that most of the fluid waste stream will be produced water generated after the field has been producing for about five years. Throughout the project life, the injection well(s) will be used to dispose of camp sewage and grey water, waste fluids intrinsically associated with oil and gas exploration and production, and a variety of non-hazardous industrial waste fluids generated onsite.

A general breakdown of the volumes to be injected over a 20-year period, as estimated by ARCO, are shown below:

Type of Waste	Approximate Volume
Produced Water (maximum case)	14,000,000 barrels
Well completion and workover fluids and solids, rig wash water, drilling mud, well flush water, process facility wastes, etc.	3,250,000
Camp sewage and other domestic wastewater	1,700,000
Non-hazardous industrial waste	50,000
TOTAL	19,000,000 barrels

Most of the waste to be injected will already be in liquid form and thus not require any slurrying or other type of special handling. Wastes which will require some slurrying include frac sand, vessel sludge, line pigging materials, pipe scale, incinerator ash, contaminated gravel, and (if necessary) drill cuttings. ARCO intends to dispose of most drill cuttings either through annular injection as part of the well construction process or through a dedicated Class II injection well, and both of those practices are regulated under permit by AOGCC. However, the Class I injection well to be permitted by EPA could also be used to dispose of drill cuttings if needed.

ARCO has not applied for a hazardous waste injection well permit. Therefore, any listed hazardous wastes will need to be collected, stored, and transported to a RCRA-permitted hazardous waste treatment or disposal facility. Those wastes which are hazardous only because of a characteristic (such as ignitability, corrosivity, toxicity, etc.) may be treated to remove that characteristic and then injected as a Class I non-hazardous waste fluid. The permit does not allow injection of radioactive wastes, as defined in the UIC regulations. Naturally occurring radioactive material (NORM) from sludge or pipe scale (a mineral precipitate formed during production) may be injected.

Geologic Setting and Injection Issues

The geologic setting at the Alpine field area is favorable for fluid waste disposal via injection wells. The stratigraphic sequence and lithology are correlative with the formations found at Prudhoe Bay, where Class II injection wells have operated successfully for almost two decades.

The proposed permit would allow injection into the Ivishak and Sag River Formations of Permian/Triassic age. The Ivishak Formation, which is the lower of the two, contains several porous (about 15%) and permeable (about 30 millidarcies) sandstone intervals which ARCO expects to encounter between about 8900 and 9600 feet below the land surface in the first disposal well. The uppermost sandstone of the Ivishak Formation is separated from the Sag River Formation by about 150 feet of shale and siltstone within the Ivishak, and roughly 300 feet of Shublik Formation limestone. The Sag River Formation is projected to be encountered at 8500 feet below the land surface. In the offsetting Nechelik well, the Sag River Formation is an approximately 50-foot thick interval of porous (about 19%) and permeable (about 120 millidarcies) sandstone.

ARCO estimates that the waste plume, if injected into a single well completed only in the Ivishak Formation, will extend radially around that wellbore almost 3400 feet. If both the Sag River and Ivishak are utilized, the waste plume is likely to extend radially about 2800 feet. Pressure effects from the proposed injection will extend beyond the fluid waste plume itself. Assuming that both the Ivishak and Sag River are utilized for injection, the reservoir pressure is anticipated to rise about 150 pounds per square inch (psi) at the wellbore, just under 100 psi a mile away, and just under 50 psi at a distance of seven miles. Given an original pressure of 4300 psi, these increases above background would be about 3.5%, 2.3%, and 1.2% respectively. These pressure increases are not expected to compromise the integrity of the overlying shale and siltstone confining zone.

The Sag River Formation, which would be the uppermost permitted injection interval, is separated from the overlying Nechelik tight oil zone and the Alpine field oil-producing horizon by about 900 feet of Jurassic age lower Kingak Formation shale and about 300 feet of Jurassic age upper Kingak Formation siltstone. The Kingak Formation will serve as the arresting and confining zone. Above the oil-producing stratigraphic horizon at Alpine lie more than 5000 feet of Cretaceous shale and siltstone, and about 800 feet of permafrost.

The strata at Alpine are almost horizontal, dipping about 1 to 2 degrees to the southwest, and are unfaulted above the proposed injection interval. Northwest-trending normal faults, which are interpreted to have as much as 50 feet of displacement within the Ivishak Formation, die out in the thick shale section of the lower Kingak Formation. Available evidence suggests that the faults do not naturally act as fluid conduits. Any preferential fluid movement along the faults which might occur during injection would likely be restricted to the Ivishak Formation itself.

Both the Ivishak and Sag River injection intervals are naturally saline. ARCO reports that water samples taken from flow tests were measured to have about 23,000 mg/L of TDS, or more than twice the 10,000 mg/L regulatory threshold used to define a USDW. Generally speaking, formation water salinity increases with depth, and so ARCO has used available information to estimate the quality of ground water found in aquifers above the injection intervals and below the permafrost.

Since no water samples have been taken above the oil-producing zone, these ground water quality estimates are based upon the analysis of geophysical borehole logs. These logs are records of the natural gamma radiation, density, and electrical conductivity of the rock and formation water measured before the borehole was cased. Review of these logs show that there are few clean (free from clay minerals or coal) sandstones within the stratigraphic section between the oil-producing horizon and base of the permafrost. Borehole log analysis of these few intervals suggests that they have formation water above the 10,000 mg/L TDS level which defines a USDW, and most of these few clean sandstones have formation water with an estimated TDS concentration of about 20,000 mg/L.

ARCO submitted information to support an aquifer exemption request in the event that EPA were to determine that some aquifers beneath the permafrost are fresh enough to qualify for protection as USDWs. This aquifer exemption request points out that ground water beneath the permafrost is not utilized as a drinking water supply anywhere on the North Slope, estimates the expense of extracting and treating the brackish to saline ground water for use as drinking water, and documents the availability of abundant fresh surface water resources which can be inexpensively treated for use as drinking water. In response, EPA has reviewed the geophysical borehole logs, ARCO's log analysis, the opinion of an AOGCC geologist with expertise in log analysis, and concluded that the available information suggests the few aquifers found beneath the permafrost at Alpine are too naturally saline to qualify as USDWs.

Since the proposed well(s) will not inject below a USDW, EPA may allow less stringent requirements for area of review, construction, mechanical integrity, operation, monitoring, and reporting than would otherwise be required by the UIC regulations (see 40 CFR 144.16). At the Alpine field, EPA intends to only relax some of the operating and monitoring requirements, as described below.

Compatibility of Formation and Injectant: Based upon the applicability of past injectibility studies and injection practices at Prudhoe Bay and other North Slope fields, EPA intends to waive the requirements of 40 CFR 146.12(e) and 146.14(a) which require sampling and characterization of formation fluids and matrix in order to determine whether or not they are compatible with the proposed injectant.

Injection Zone Fracturing: Class I injection wells are prohibited from injecting at pressures which would initiate new fractures or propagate existing fractures within the injection zone. The draft permit instead allows hydraulic fracturing within the injection zone so long as new fractures are not initiated nor existing ones propagated within the upper confining zone.

Injection will be limited to the Ivishak and Sag River Formations. The uppermost injection interval (Sag River Formation) is about 8500 feet beneath the land surface, and approximately 1000 feet below the oil-producing horizon. The strata between the Sag River and the overlying oil-producing stratum is composed mostly of practically impermeable shale and siltstone.

Ambient Monitoring Above the Confining Zone: EPA intends to waive the requirement to monitor the strata overlying the confining zone for fluid movement (see 40 CFR 146.134). The principal purpose of this requirement is to protect overlying USDWs, which are not present at Alpine.

Summary of Proposed Action and Permit Conditions

EPA has primary enforcement authority in Alaska for Class I injection wells as they are regulated by the UIC program, which is authorized by Part C of the Safe Drinking Water Act. EPA grants Class I injection well permits are granted to ensure that waste fluids are safely injected for disposal beneath any existing USDWs, and remain below the confining zone. EPA proposes to grant a permit to ARCO for up to three Class I non-hazardous waste injection wells at the Alpine field, located in the Colville River delta on the North Slope of Alaska. EPA has considered all of the available disposal options, and concludes that underground injection is the most appropriate way to dispose of non-hazardous fluid waste generated at the Alpine field.

Based upon available information, EPA has determined that there are no USDWs beneath the Alpine field area. Considering the absence of USDWs, EPA proposes to grant ARCO a waiver of the UIC program regulation which prohibits hydraulic fracturing of the injection zone during operation (40 CFR 146.13). This waiver is necessary to enable the injection of fluid wastes which contain a small fraction of solid material, and is authorized by the UIC program regulations under 40 CFR 144.16a.

The draft permit contains general legal provisions common to all EPA UIC program permits, specific technical requirements which apply to all Class I injection wells, and particular technical requirements for the proposed injection operation. EPA contacts for further information are Grover Partee at (206) 553-6697 or Jonathan Williams at (206) 553-1369.

4.0 AREA OF REVIEW

4.1 Introduction

All underground injection wells must meet performance standards that prohibit movement of fluid containing any contamination into underground sources of drinking water (USDW) per 40 CFR 144.12. However, despite the lack of any identifiable drinking water source below the permafrost, the EPA has historically required a demonstration that contaminants cannot move into any saline aquifer(s) that lie above the confining zone.

To meet this performance requirement, the regulations require a description of the geological and hydrological structure of the subsurface area, 40 CFR 146.14(a)(4)-(6); and that transmissive faults or open conduits through the confining zone within the area of review be accounted for, 40 CFR 146.14(a)(3)-(4).

The Area of Review (AOR) is either regulatory (1/4-mile radius for Class I Industrial injection wells) or it is based upon the calculated injection pressure build-up radius sufficient to move fluids into any overlying aquifer. This pressurized area is termed the zone of endangering influence (ZEI). If the ZEI is larger than the statutory AOR, it becomes the appropriate area to make no contamination demonstrations. The following discussion justifies a 1/4 mile AOR instead of one based on the ZEI.

CPAI believes that the ZEI is no larger than the statutory AOR and recommends that the AOR be set at 1/4 mile. A 1/4 mile AOR is consistent with the facility's first Class I well permitting in the Sag River and Ivishak Formations.

4.2 Project Management AOR

<u>Fracturing and Development Drilling:</u>

Fracturing of the injection zone is expected to be 700 feet or less radially. This will not conflict with field development since the injection zone is much deeper than the hydrocarbon reservoir, and it is overlain by 1500 feet of confining shale. Exhibit 4-1 shows disposal well penetrations on the Sag River Depth Structure map.

<u>Disposal Zone Pressure Buildup:</u>

Based on modeling, Exhibit 4-2 shows how CD1-19A pressure buildup looked after the end of injection assuming the maximum volume of waste associated with the project was injected only into that well. At the end, the increase will be 105 psi at a distance of 1/4 mile from the injection point in a most extreme scenario. At 1/2 mile it will be 100 psi. After injection ceases it will gradually decline from about 50 psi above original pressure to original pressure.

<u>Waste Plume Location:</u>

A radial disposal domain for 19 MMB will generate a plume radius of about 2000 feet if the Ivishak Formation is used exclusively for disposal. Since there is no natural horizontal pressure gradient in the Sag River and Ivishak formations, and the injected fluid is about the same density as the in-situ brine, there should not be any fluid migration after injection ceases.

Associated Wells

Based on top Sag River penetration, the closest existing well to the WD-02 disposal location is about three thousand feet away as shown on Exhibit 4-1.

Exhibit 4-3 shows the surface location of WD-02 on CD1 pad, as well as water flow contours. Exhibit 4-4 shows CD1 pad, water flow contours, and the surrounding area.

Fault Influences:

There are no transmissive faults in the AOR.

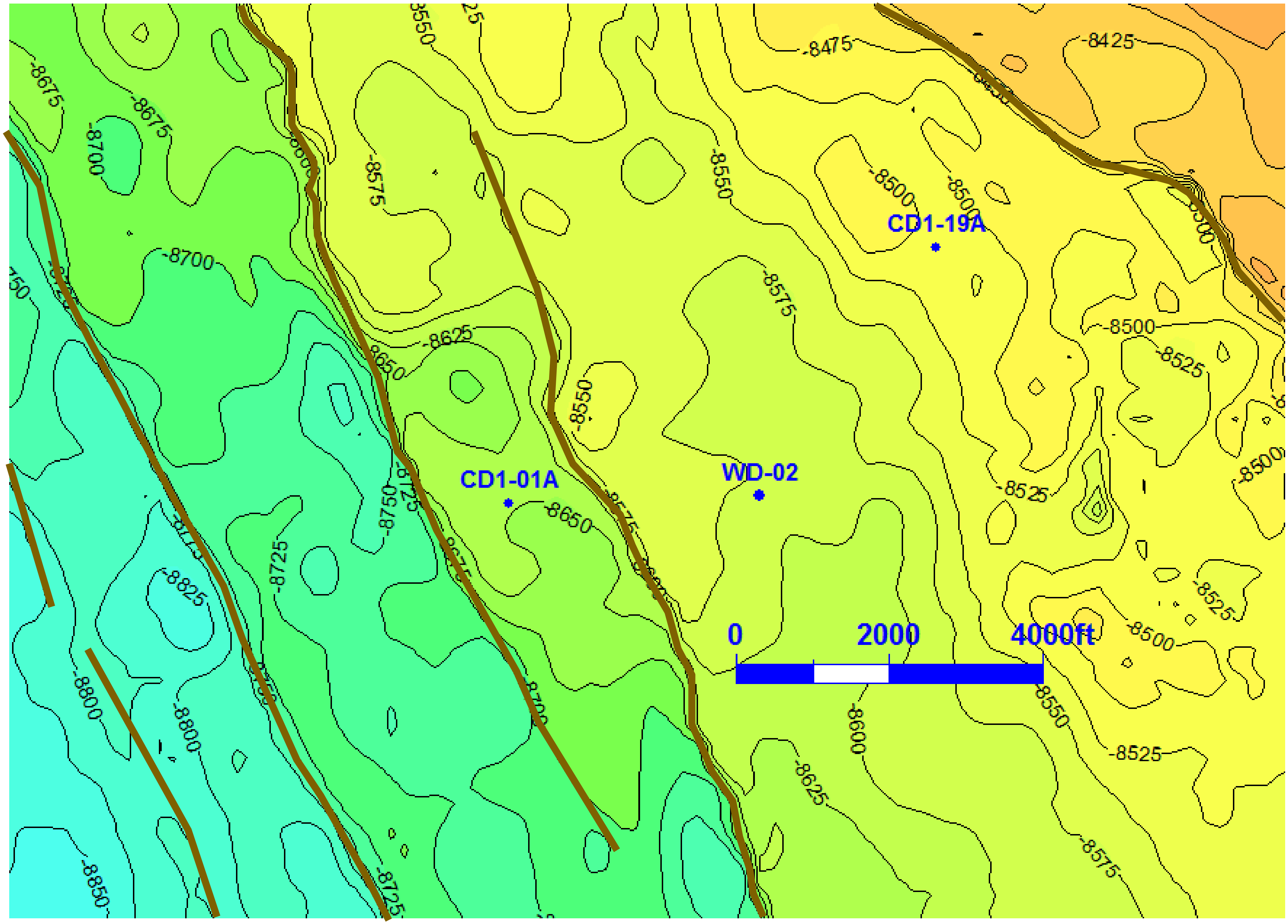
Conclusion:

CPAI has no wells within the ¼ mile AOR that require corrective action in order to prevent fluids from moving above the confining zone. CPAI believes that the ZEI is no larger than the statutory AOR and recommends that the AOR be set at 1/4 mile. A 1/4 mile AOR is consistent with the facility's first Class I well permitting in the Sag River and Ivishak formations.

If CPAI later discovers that a well within the AOR that requires corrective action to prevent fluid movement, then CPAI will inform EPA upon such discovery and provide a correction action plan for EPA review and approval. If EPA or CPAI discovers that fluids have moved above the confining zone along a wellbore within the AOR, then injection shall cease until the fluid movement problem can be diagnosed and corrected.

Exhibit 4-1

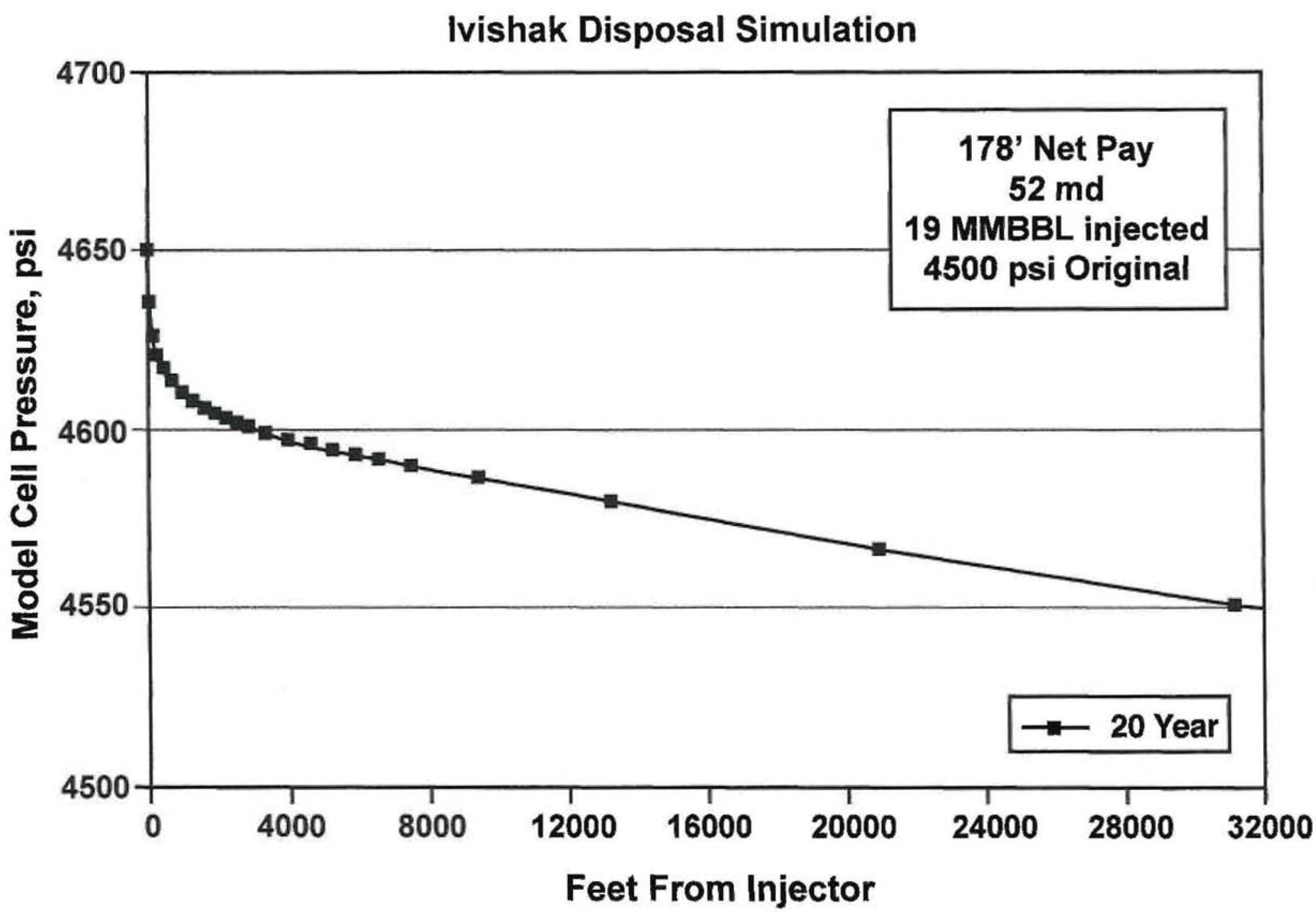
Area of Review (well penetrations on top Sag River Fm)



ConocoPhillips

EXHIBIT 4-2

ALPINE CD1-19A MAXIMUM DISPOSAL PRESSURE BUILDUP (DUE TO WASTE INJECTION)



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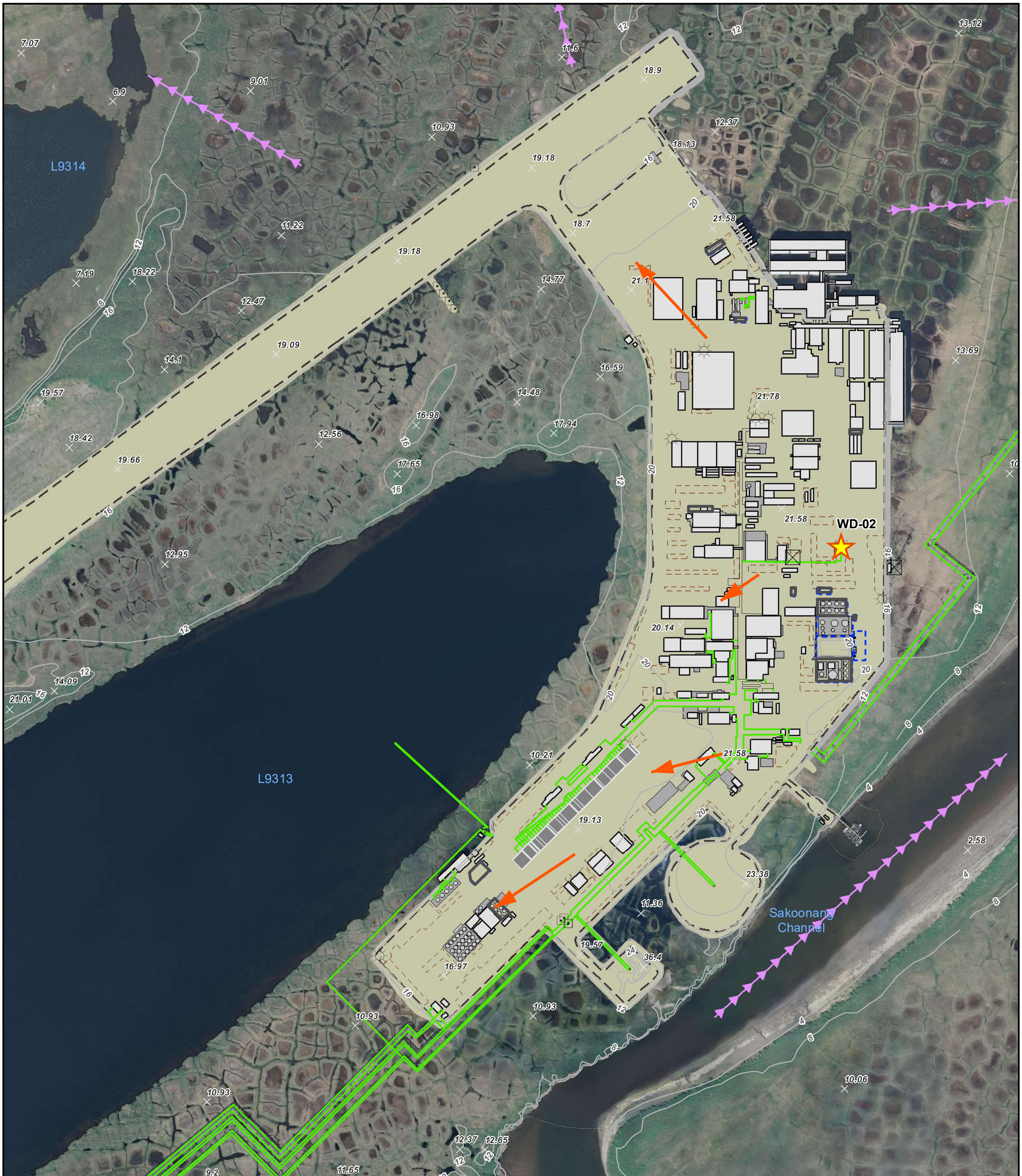


Exhibit: 4-3

Colville Delta 1

WD-02 Well

WD-02 Well

Well House

Pipeline

Contour (2' interval)

On-pad Flow

Surface Flow

N

ConocoPhillips Alaska, Inc.

0 200 400 Feet

March 29, 2018

Document Name: ALP_CD1_01A_UIC_ClassI_WellDetail

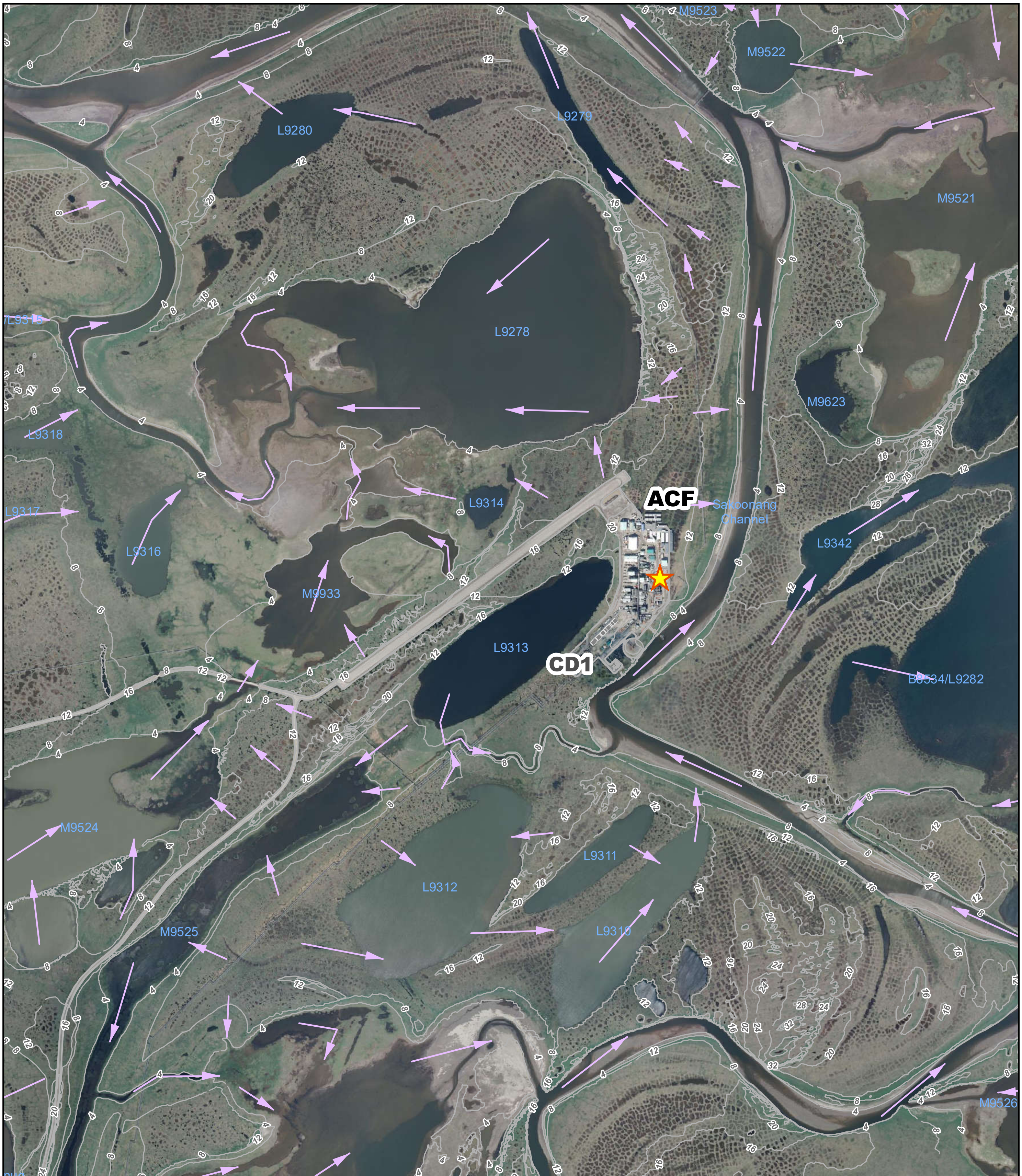


Exhibit: 4-4

COLVILLE DELTA 1

Area Map

WD-02 Well

Surface Flow

Contour (2' interval)

N

ConocoPhillips Alaska, Inc.

0 0.25 Miles

March 29, 2018

Document Name: ALP_CD1_01A_UIC_ClassI_WellArea

5.0 RESERVOIR AND WELL PERFORMANCE

5.1 Formation Testing and Monitoring

There have been no notable, adverse operational incidents with well WD-02 since the well was completed in April 1999. Operational events of significance (see Exhibit 7-7) for the WD-02 well can be summarized as follows:

- 24 mechanical integrity tests on the inner annulus (MITIA)
- Tubing string replaced in 2011 after failed MITIA
- Flo-Seal Treatment to seal suspected packer leak after failed MITIA in 2012

Step Rate Test:
A SRT was performed on well WD-02 in April 1999, and a plot of the results is included as Exhibit 5-1. The formation broke at 1.4 BPM using 8.5 ppg brine with 1980 psi on the tubing. The fracture gradient is 0.66 psi/ft. This is in good agreement with Ivishak fracturing at Prudhoe Bay Field and with the gradient of 0.63 psi/ft obtained from previous Class I well CD1-19A.

Given an SRT has been completed and it correlates well with other North Slope locations, CPAI requests that the EPA not require another.

Pressure Falloff/ Shut-in Pressure Surveys:
Exhibit 5-2 shows the PFO for WD-02 obtained in March 2002 prior to the annual compliance testing. With 8.3 ppg freshwater in the well and 700 psi at the surface, the curve generates a reservoir pressure gradient of 0.491 psi/ft. The reservoir pressure at 9200 feet TVD is 4517 psi. The 0.491 psi/ft gradient is the same as was measured for the CD1-19A PFO.

CPAI does not anticipate completing another PFO unless it is required or unless operational needs are identified. Reservoir static pressures can be obtained in the future between injection cycles as needed. It is requested that the EPA not require another PFO at this time.

Channel Logging:
A channel log, most likely an oxygen activation log, will be performed every other year. Subsequently, it is proposed to run a temperature log every other year to confirm waste confinement. CPAI proposes to continue running these logs in coordination with annual MIT testing on CD1-01A. The last dual oxygen activation and temperature logs were run March 4th, 2018. The surveys indicated no out of zone injection or leaks in the tubing and production casing above the perforated intervals.

5.2 Annulus Pressure Testing

The inner annulus and packer were tested to 3500 psi upon completion of the WD-02 well. The inner annulus has since had 23 MITIA's run; the first at 3500 psi. The last MITIA was run on March 3rd, 2018, where the inner annulus was tested at 3510 psi, demonstrating mechanical integrity of the tubing, production casing, and production packer.

Since operational conditions are not anticipated to change, CPAI proposes to continue performing annual MITIA's in coordination with CD1-01A' s annual MITIA.

5.3 Well Stimulation

No well stimulation activities have been carried out on WD-02.

5.4 Corrosion Effects

To date no significant corrosion or erosion has been detected in the well. Mechanical integrity testing over the life of the well, including caliper surveys and pressure tests of the inner annulus, have not indicated metal loss concerns. Valve or surface piping has not shown the need for replacement. Should concern arise, diagnostic tools would be employed and any marginal equipment would be replaced.

5.5 Injection Pressure

Exhibit 5-3 illustrates the injection pressure, inner annulus pressure, and injection rate since injection was initiated in May 1999. The injection pressure shows excursions typically due to annual compliance testing activities or other wellwork operations. Daily average flow rates average around .7 BPM and range from 0 – 1 BPM as the injection pumps cycle off and on throughout the day. The flow rate displays a seasonal pattern peaking in the winter during ice road season when the camps are full.

CPAI requests the EPA recognize the previous successful operations and not place an injection limit on the well that would restrict its operation as future pump and piping changes are possible.

The future injection pressure is expected to continue the existing trend, as follows:

1. Average Injection Pressure 1300 – 1700 psi
2. Maximum Injection Pressure 3200 psi

Waiver Request: Pursuant to 40 CFR 144.16, CPAI requests that the EPA waive the prohibition against fracturing the injection interval as outlined in 40 CFR 146.13(a)(1).

Additionally, CPAI requests that the EPA continue to permit the disposal well to operate at a maximum injection pressure of 3200 psi, with temporary spikes exceeding this limit for compliance testing activities and transmitter maintenance, up to the 5000 psi working pressure of the wellhead. Injection operations will conform to 40 CPR 146.13 (a) which prohibits fracturing of the confining zone. (See Section 6.0 for additional fracturing discussions).

5.6 Compatibility of Fluids and Formation

Well WD-02 has injected 6.1 million barrels of graywater and produced water into the Ivishak Formation as of January 1, 2018. A very large amount of similar slurry and other wastes have been injected at numerous other sites across the North Slope for over 30 years; therefore, it is well established that there is no compatibility problem between these injectants and the receiving sandstone formations. Additionally, 1.3 million barrels have been injected into well CD1-01A three thousand feet away, the bulk of it being drilling fluids and drill cuttings. Proof of fluid and formation chemical compatibility is well established in other reports to the EPA and the State of Alaska. These are available upon request.

Waiver Request: CPAI requests a waiver from the requirements of 40 CFR 146.12 (e) (4) – (5) and 146.14 (a)(8) that requires (1) sampling and physical/chemical characterization of formation fluids, and proof that the injectant is compatible with formation waters and; (2) sampling and physical/chemical characterization of the injection matrix.

Exhibit 5-1 WD-2 Step Rate Test

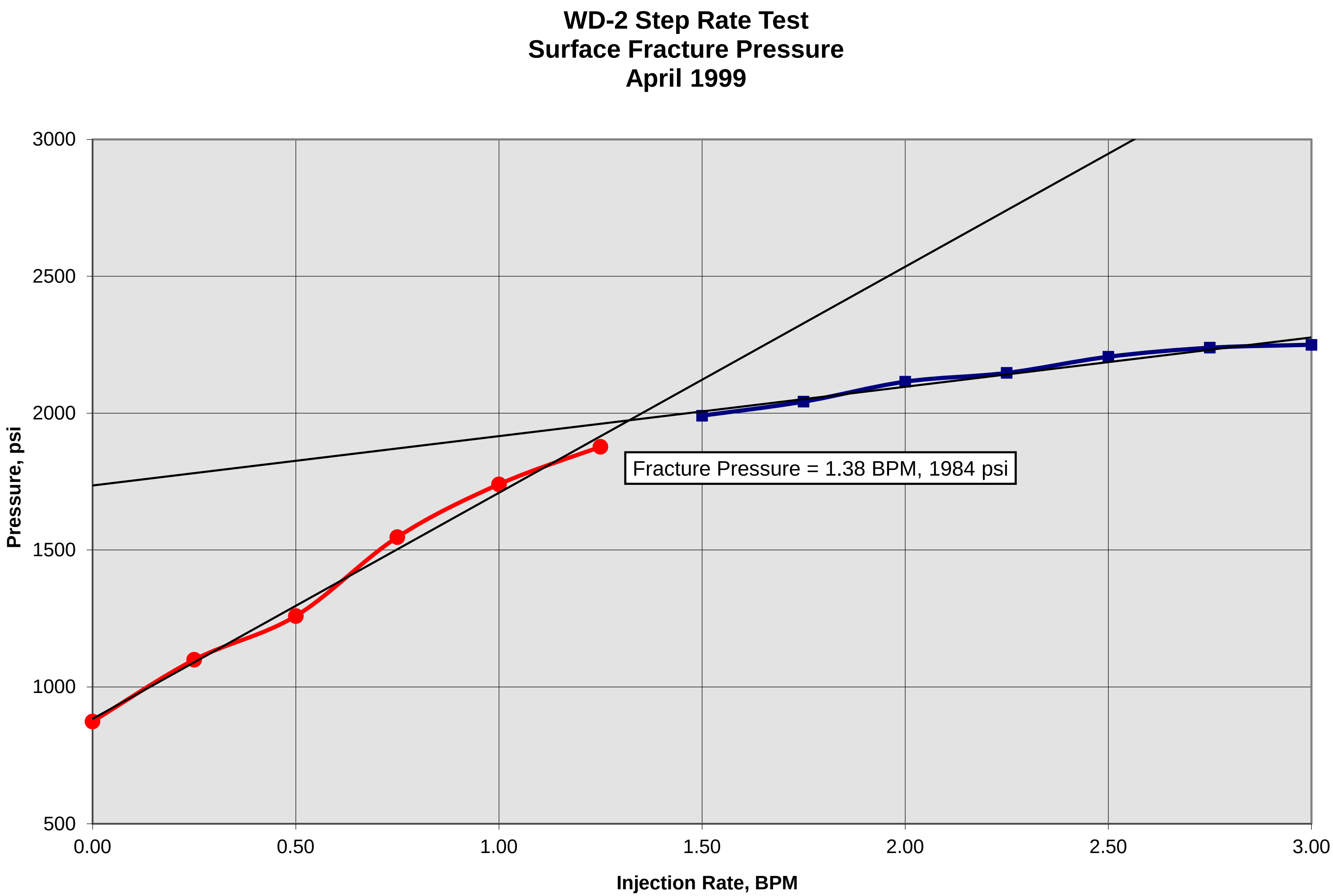


Exhibit 5-2 WD-02 Pressure Fall-Off

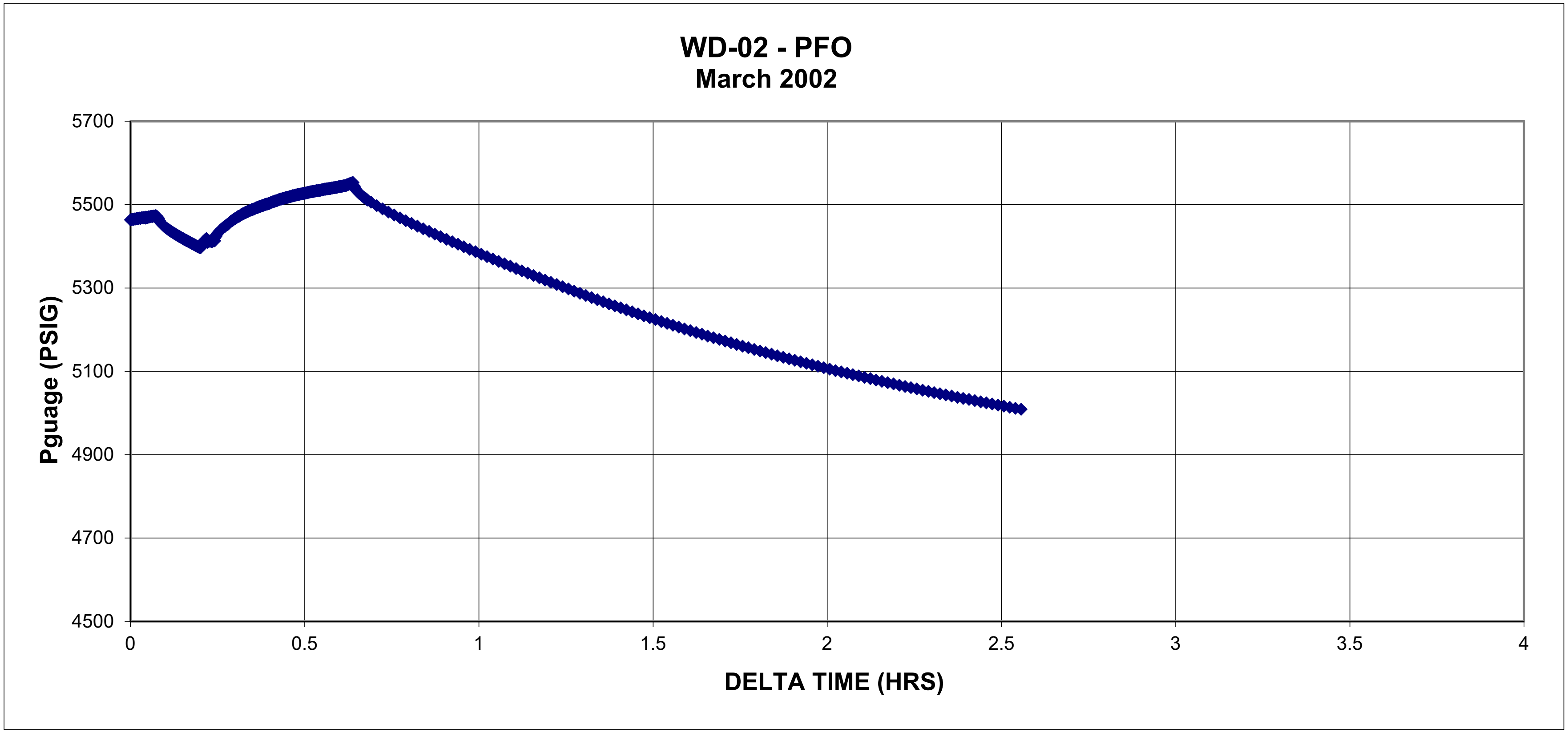
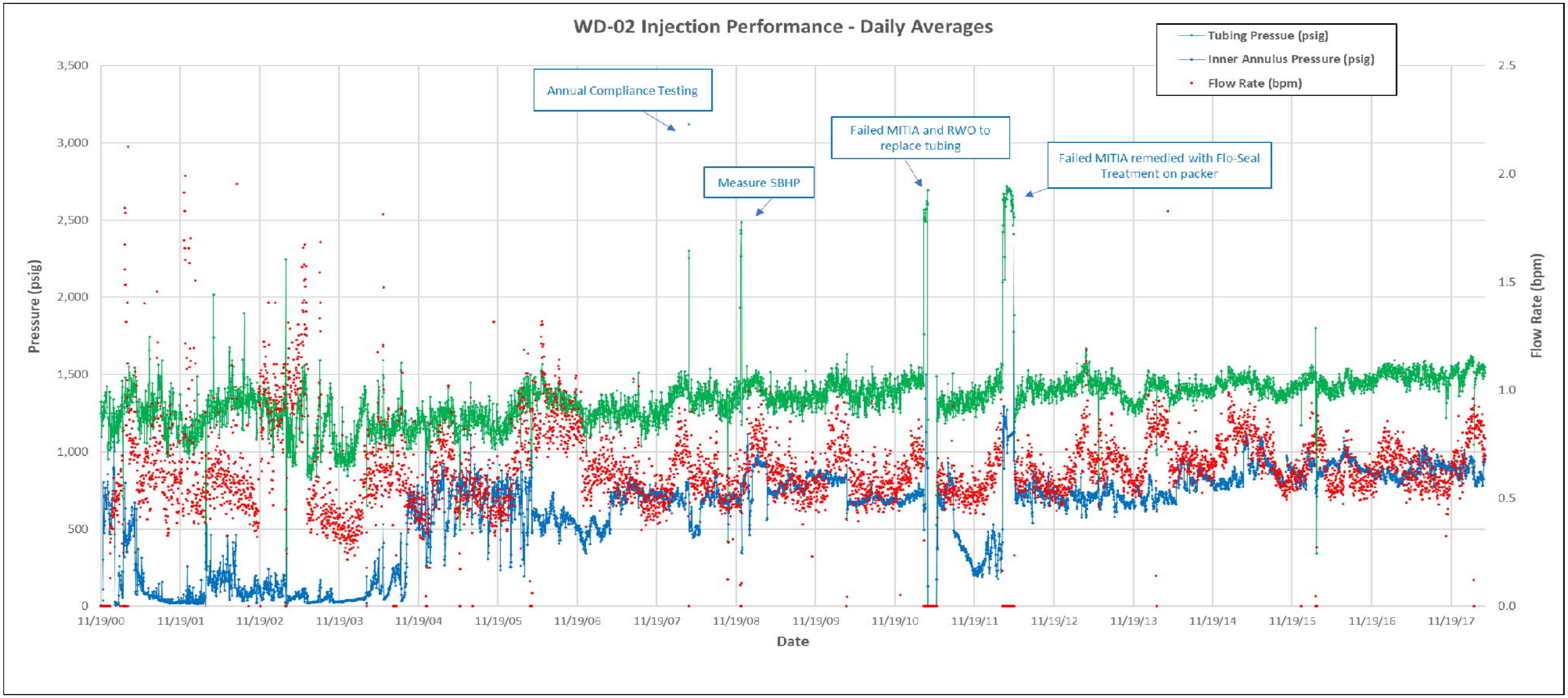


Exhibit 5-3 WD-02 Well Performance Plot



6.0 PERFORMANCE STANDARDS AND COMPLIANCE

6.1 Waste Confinement

Hydraulic Fracturing:

To investigate formation fracturing effects, a modeling study was undertaken in August of 2007 to help quantify the behavior of injecting solids slurry into the Ivishak Formation associated with well CD1-19A. An industry-available three-dimensional hydraulic fracturing simulator was used to predict fracture growth during slurry injection. A prominent licensed commercial product was employed; built and maintained by Meyer and Associates, Inc. for industry use. The study was conducted by an ASRC Energy Services geophysical consultant and is provided in Appendix B.

Rock properties used in the model were based on laboratory core experiments from offset wells and data from sonic log derived parameters. Disposal well CD1-19A is mainly completed in the lower section of the Ivishak. This lower section was programmed to be used in conjunction with some upper Ivishak perforations.

Fracture modelling cases were run using 10.1 ppg slurry, a rate of 3.5 BPM, and for volumes at 2500 Bbls. Different fracture geometries that developed for various types of completion scenarios were also investigated using the most extreme operating conditions. A sensitivity case using reduced rock permeability and a low leak-off parameter was also run. In addition, a situation was run with grind-inject slurry injected only into the Sag River Formation. This generated a slight penetration of the overlying massive confining zone. Nineteen of the above cases are included in the Appendix B report.

Exhibit 6-1 summarizes results from the fracturing study. Exhibit 6-2 shows the expected fracture profiles. It can be seen that fracture half-lengths ranged from about 400 feet to about 600 feet. Sensitivity cases using the most extreme operating conditions generated a fracture approaching 800 feet using only the current existing perforations in the Ivishak. In no case did the fracture grow out of the Ivishak formation. Wastes were confined to the lower injection zone under all excessive conditions, with perforations as they now exist.

Geologic Faulting:

There are no transmissive faults in the general area. The few minor faults that exist have little throw and the sands are frequently juxtaposed against shale.

Uncemented Wellbores:

Based on top Sag River penetration the closest existing well to the disposal location is about three thousand feet away. Should any well be drilled in the nearby area and penetrate the injection zone it will be fully cemented and isolated.

Conclusions:

- Confinement problems will not occur due to hydraulic fracturing during waste disposal operations.
- There are no fault transmissibility issues.
- There should not be any uncemented wellbore problems.
- As mentioned in Section 4.0, the waste plume will not migrate when injection ceases.
- There are no vertical or horizontal confinement issues associated with waste injection.

6.2 Ambient Monitoring of Overlying Strata

There are no USDWs below the permafrost. There are no improperly sealed, completed, or abandoned wellbores within the AOR or nearby area. Section 3.0 data shows that the geological formations are continuous and the minor faults in the far-field areas are sealing. While fracturing will occur at the injection well it will be confined. Development wells drilled in the area will be at least 1,200 feet shallower than the disposal zone. There is limited chance of any waste penetration of the confining zones, based on 18 years of disposal history in the Ivishak formation at the Alpine Field, and such an occurrence must be viewed as miniscule. CPAI therefore proposes not to conduct ambient monitoring in the formations overlying the injection zone.

Waiver Request: Based on the above facts, a waiver is requested from 40 CFR 146.13(b)(1) and (4) and 40 CFR 146.13(d) to the extent it would otherwise require monitoring of overlying strata, or monitoring at any external location in the injection zone. This request is consistent with 40 CFR 144.16, which allows the Director to waive monitoring requirements when there are no underground sources of drinking water to protect.

Exhibit 6-1

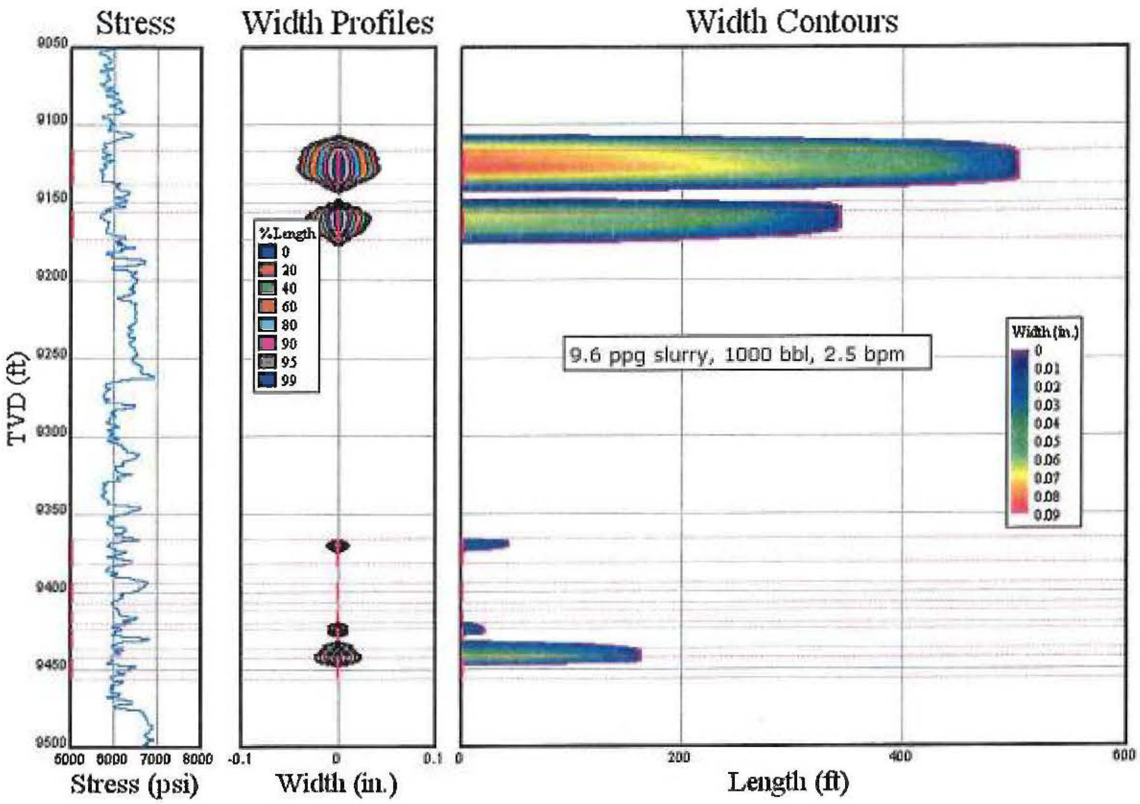
Fracture Modeling for CD1-19A Waste Injection

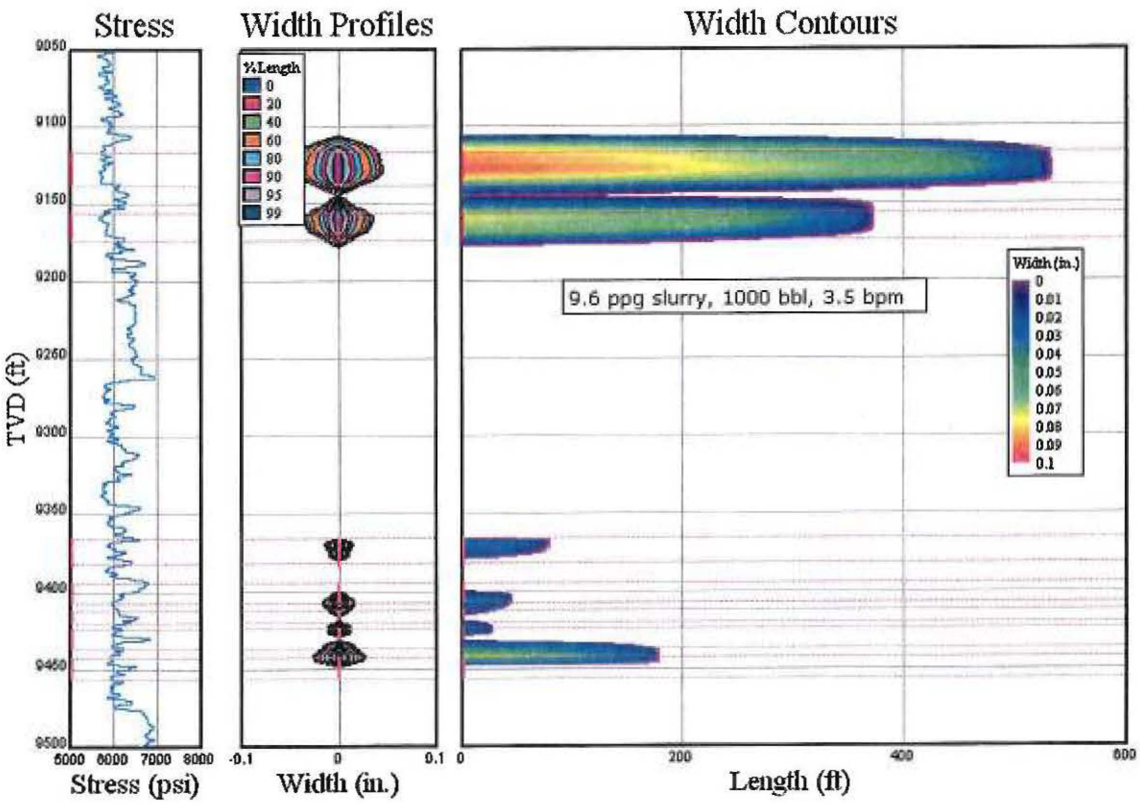
(((Dimensions vary depending upon how well is completed. Numbers shown are averages)))

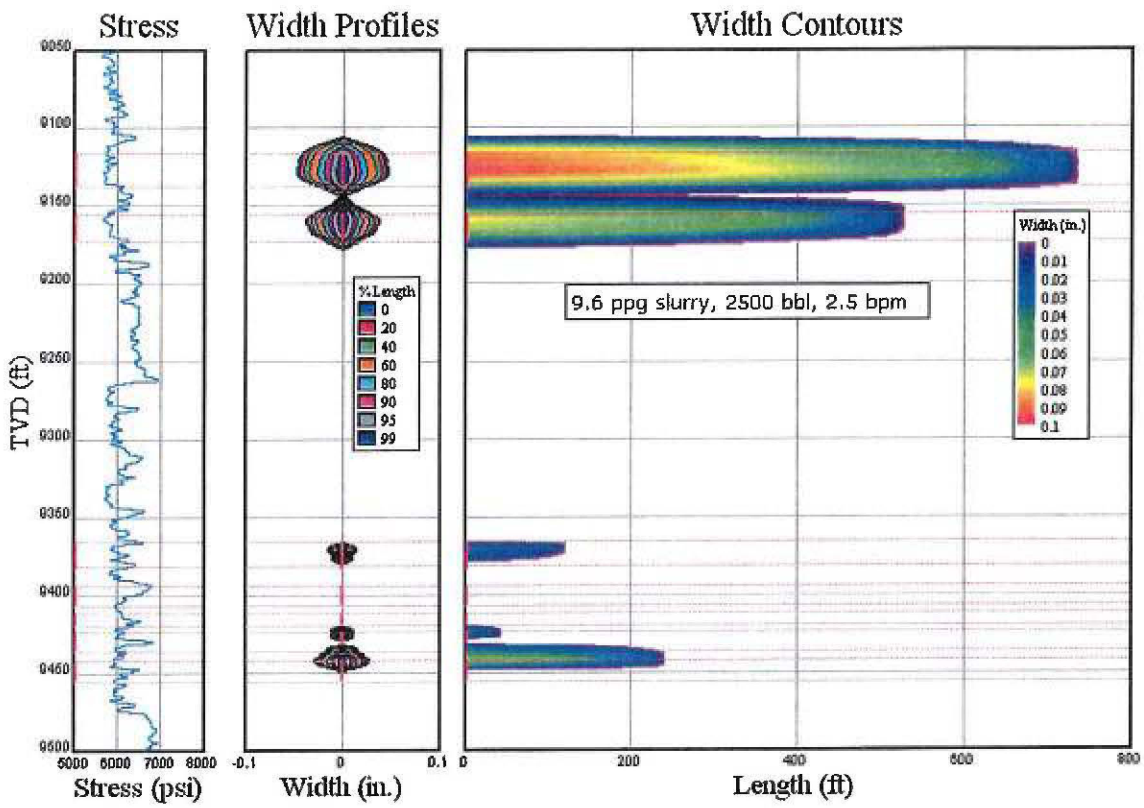
		Expected Volume	Maximum Volume
			((Sensitivity Cases))
		1000 Bbls Slurry	2500 Bbls Slurry
Expected Case	**9.6 ppg slurry injected at 2.5 BPM**		
Frac Half length	Feet, Approximate	350-500	520-730
Frac Total Height (up plus down)	Feet,	75	75
Frac Width	Inche	0.08	0.1
Rate Sensivity	**9.6 ppg slurry injected at 3.5 BPM**		
Frac Half length	Feet, Approximate	370-540	510-790
Frac Total Height (up plus down)	Feet, Approximate	75	75
Frac Width	Inches, Approximate	0.09	0.11
Heavy Slurry Sensivity Cases			
Heavy Slurry Sensivity	**10.1 ppg slurry injected at 2.5 BPM**		
		1000 Bbls	**2500 BBls**
Frac Half length	Feet, Approximate	365	430
Frac Total Height (up plus down)	Feet, Approximate	100	135
Frac Width	Inches, Approximate	0.14	0.13
Heavy Slurry and Rate Sensivity	**10.1 ppg slurry injected at 3.5 BPM**		
		1000 Bbls	**2500 Bbls**
Frac Half length	Feet, Approximate	370	465
Frac Total Height (up plus down)	Feet, Approximate	100	135
Frac Width	Inches, Approximate	0.16	0.15

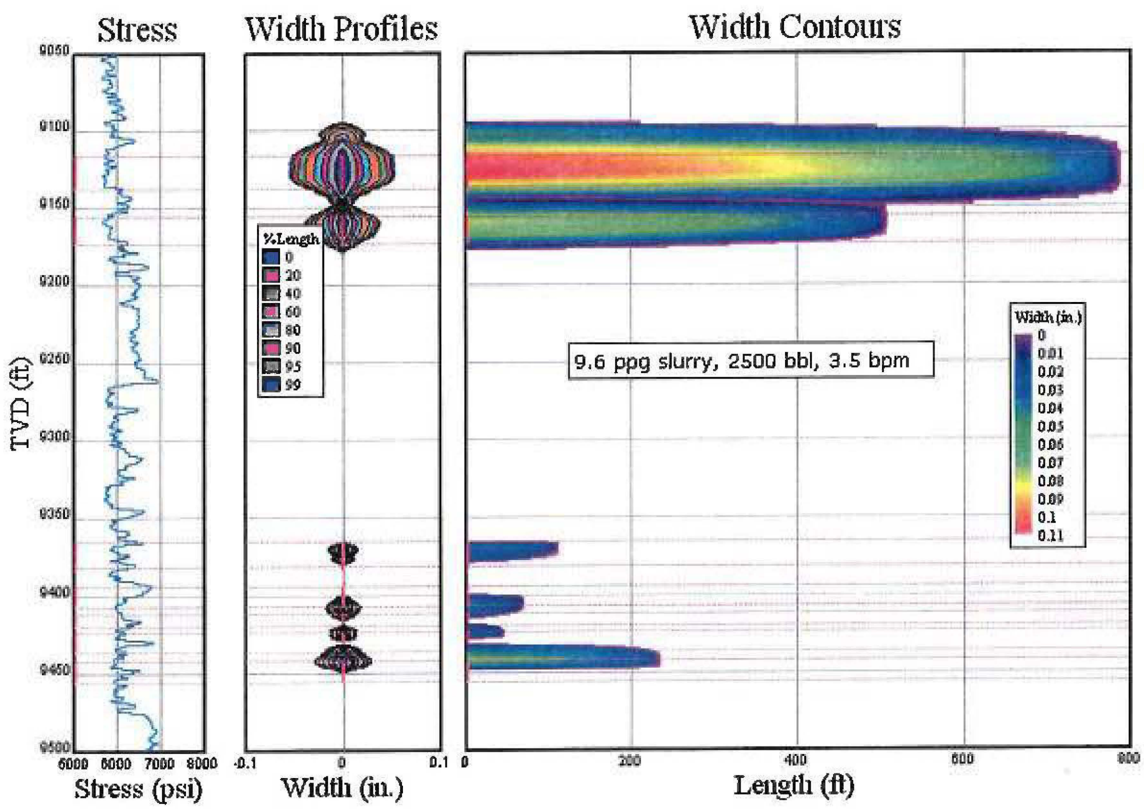
Exhibit 6-2

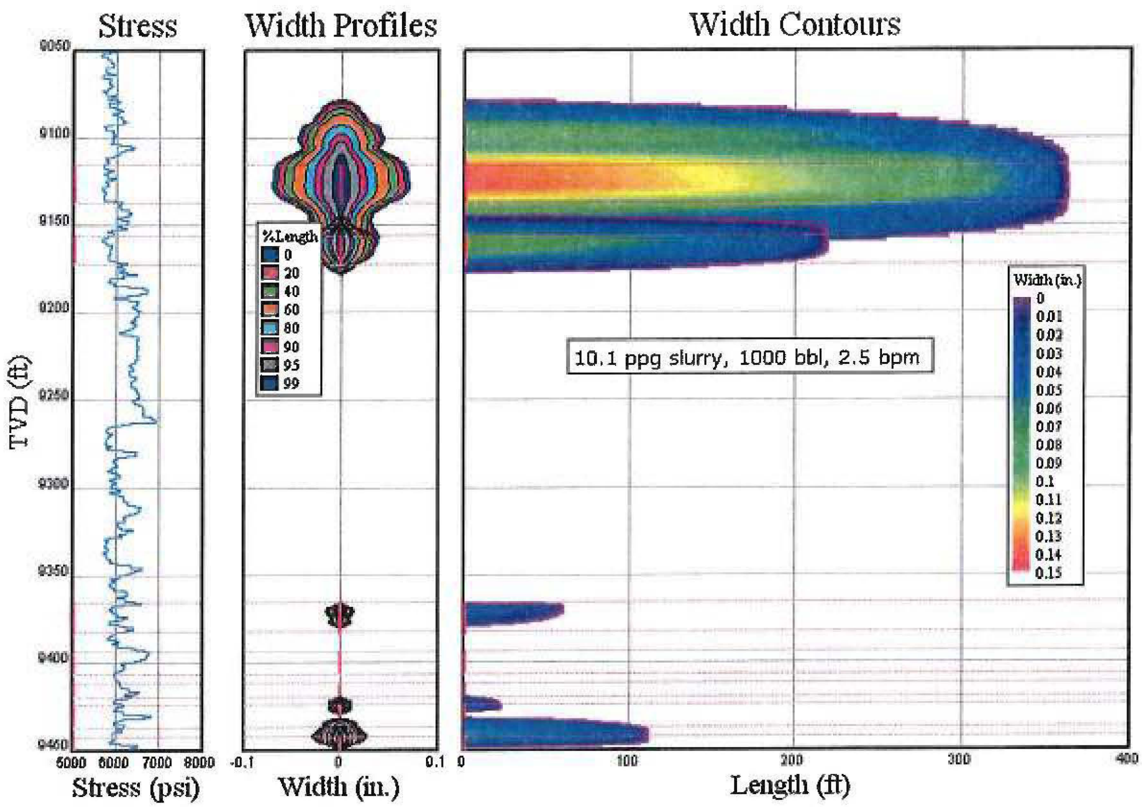
Typical Fracture profiles


Stress
Width Profiles
Width Contours
TVD (ft)
Stress (psi)
Width (in.)
Length (ft)
%Length
9.6 ppg slurry, 1000 bbl, 2.5 bpm
Width (in.)

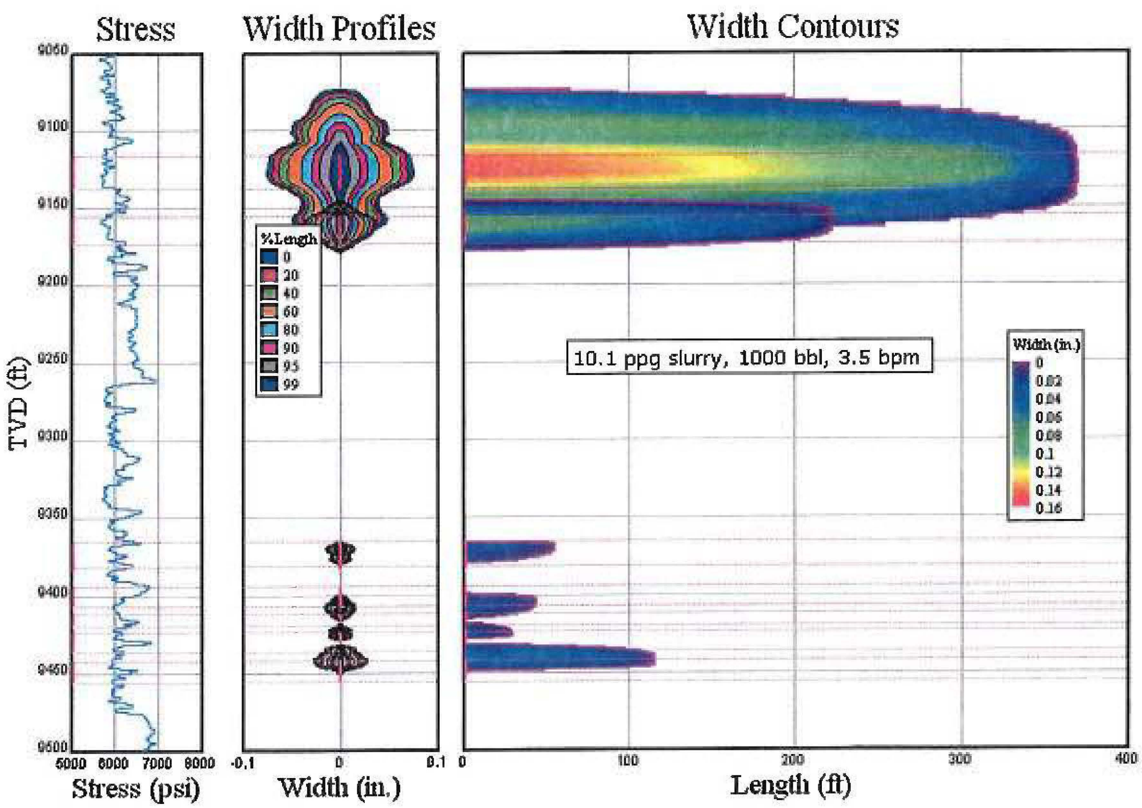

Stress
Width Profiles
Width Contours
TVD (ft)
Stress (psi)
Width (in.)
Length (ft)
%Length
9.6 ppg slurry, 1000 bbl, 3.5 bpm
Width (in.)


Stress
Width Profiles
Width Contours
TVD (ft)
Stress (psi)
Width (in.)
Length (ft)
%Length
Width (in.)
9.6 ppg slurry, 2500 bbl, 2.5 bpm

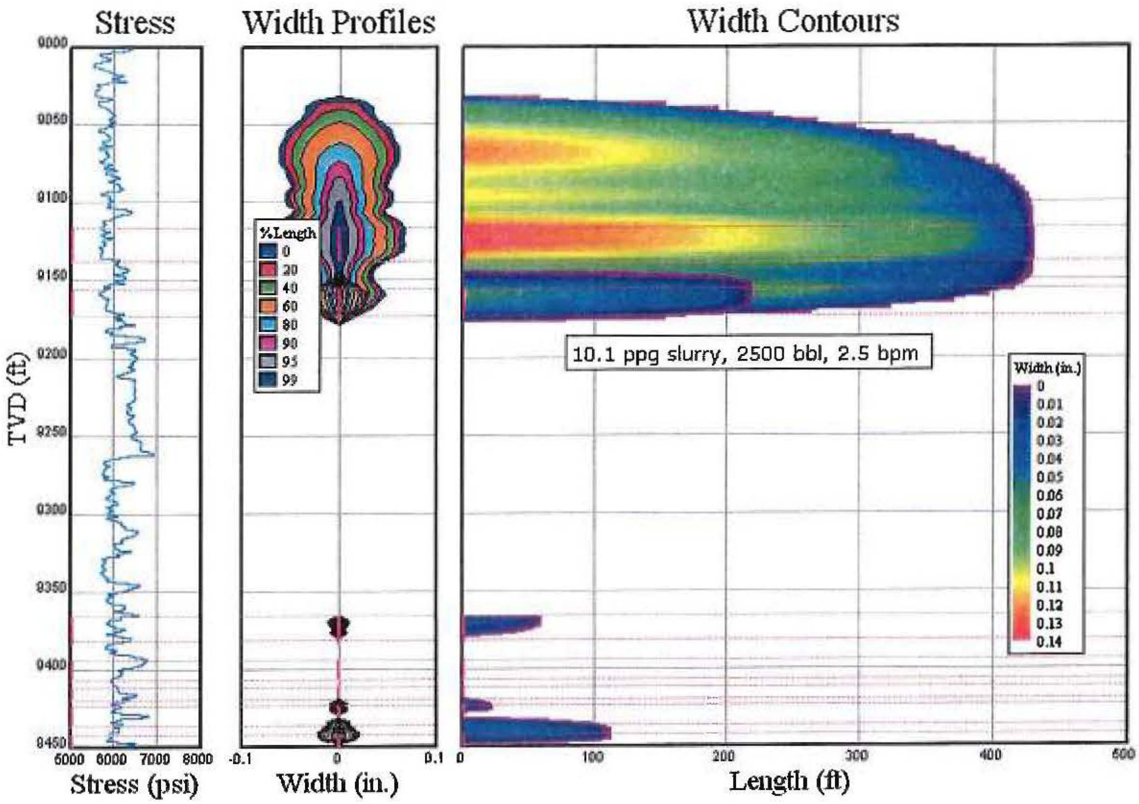

Stress
Width Profiles
Width Contours
TVD (ft)
Stress (psi)
Width (in.)
Length (ft)
%Length
Width (in.)
9.6 ppg slurry, 2500 bbl, 3.5 bpm

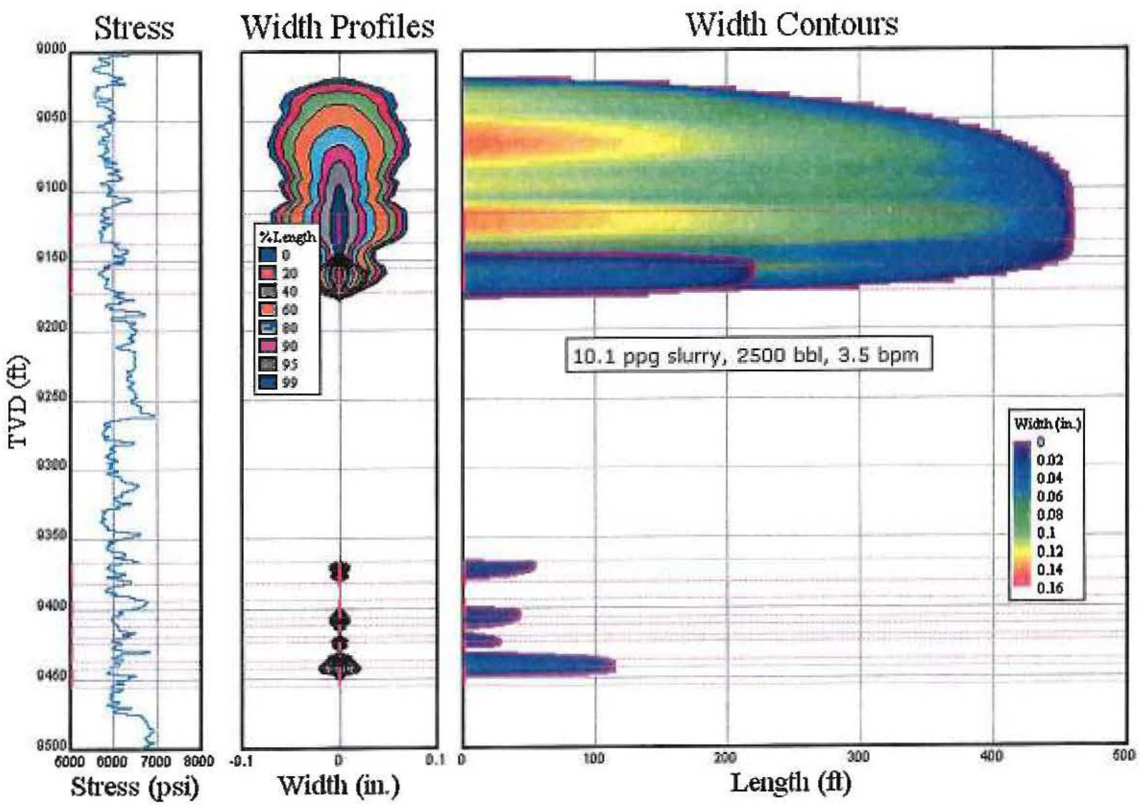


Stress
Width Profiles
Width Contours
TVD (ft)
9050
9100
9150
9200
9250
9300
9350
9400
9450
%Length
0
20
40
60
80
90
95
99
10.1 ppg slurry, 1000 bbl, 2.5 bpm
Width (in.)
0
0.01
0.02
0.03
0.04
0.05
0.06
0.07
0.08
0.09
0.1
0.11
0.12
0.13
0.14
0.15
5000
6000
7000
8000
Stress (psi)
-0.1
0
0.1
Width (in.)
0
100
200
300
400
Length (ft)



Stress
Width Profiles
Width Contours
TVD (ft)
9050
9100
9150
9200
9250
9300
9350
9400
9450
9500
%Length
0
20
40
60
80
90
95
99
10.1 ppg slurry, 1000 bbl, 3.5 bpm
Width (in.)
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0.16
5000
6000
7000
8000
Stress (psi)
-0.1
0
0.1
Width (in.)
0
100
200
300
400
Length (ft)


Stress
Width Profiles
Width Contours
TVD (ft)
%Length
0
20
40
60
80
90
95
99
10.1 ppg slurry, 2500 bbl, 2.5 bpm
Width (in.)
0
0.01
0.02
0.03
0.04
0.05
0.06
0.07
0.08
0.09
0.1
0.11
0.12
0.13
0.14
Stress (psi)
Width (in.)
Length (ft)


Stress
Width Profiles
Width Contours
TVD (ft)
%Length
0
20
40
60
80
90
95
99
10.1 ppg slurry, 2500 bbl, 3.5 bpm
Width (in.)
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0.16
Stress (psi)
Width (in.)
Length (ft)

7.0 WELL CONSTRUCTION AND INTEGRITY

7.1 Construction and Operation

The design of WD-02 exceeds all Class I well requirements listed in federal and state regulations; the well is designed so that damage from injection will be minimal. Well WD-02 was drilled in March/April 1999 and placed in injection service in May 1999. The WD-02 construction schematic is included as Exhibit 7-1. Construction details and nineteen years of operational events are included in Exhibit 7-7.

Over the life of the well there have been 24 MITIA’s of which three have failed. A failed MITIA in April 2011 was remedied by replacing the tubing in May of the same year. Two failed MITIA’s in March and April of 2012 were addressed by a Flo-Seal treatment of the packer in May of the same year. The well has demonstrated no indications of loss of mechanical integrity since then.

Annual compliance testing has occurred beginning in 2000. Up until 2005 a full suite of logs was run on WD-02 including a water flow log, spinner survey, and caliper survey; beginning in 2005 these logs have been run every other year. Fill depth tags and MITIA’s have been performed every year beginning in 2000. With the exception of the three failed MITIA’s all of the WD-02 annual compliance testing has shown that the well is in good mechanical condition.

7.2 Well Failure Plans

Well WD-02 is an existing Class I well, and the monitoring and alarm systems in place that were submitted as part of the original 1997 permit application under EPA Permit No. AK-1I003-A have been approved as meeting the monitoring requirements. The monitoring and control procedures are well established. An injection process control and equipment description for WD-02 operation is included in Exhibit 1-8.

Diagnostics will be run if injectivity suddenly rises or falls beyond predetermined limits. Either a gradual or sudden pressure increase can indicate that perforations are plugging and a well cleanout may be required. A significant decrease in injection pressure may be a sign that a new fracture system has developed, and depending upon the magnitude and character, diagnostic logs might be run. A tubing or packer assembly leak would be detected by the annulus pressure monitoring program. This problem is repaired by "killing" the well, performing diagnostics to identify the source of annular communication, then remediating the failed component.

If diagnostic tools indicate abnormal up-hole channeling, the channel would be squeezed off with cement. A follow up survey would be run to verify that the problem was corrected.

If a leak is encountered at the wellhead, injection would be shut down immediately and a plug set in the tubing to isolate the leak. The failed component could then be replaced. This problem occurs very rarely because all wellhead systems have redundant back-up sealing mechanisms. Any spill would be contained and cleaned up as outlined in the spill contingency plan.

7.3 Well Abandonment Plan

Abandonment will be implemented in accordance with procedures for waste disposal wells. At the time of final abandonment, the plan will be revised to reflect the current AOGCC regulatory requirements and/or current EPA regulations, as well as utilizing current technology applicable to the condition of the well. Both agencies will be notified in sufficient time to witness the abandonment operation. Approvals will be obtained via AOGCC Form 10-403 and EPA Form 7520-14. The current abandonment procedures are included in Exhibits 7-5 and 7-6. They detail how plugs will be set and the well left.

The Exhibit 7-9 diagram represents the abandonment scenario for the well. It is used to provide abandonment data for illustrative purposes to support the attached EPA Form 7520-14 (Exhibit 7-6). Understandably, specific action plans cannot be included in some places on the form because perforation intervals and perhaps tubular sizes will vary depending upon how the disposal process proceeds. Also, the type, grade, and quantity of cement used will depend on the well bore geometry and physical conditions existing at the time.

Should well conditions dictate a major revision in the plan, both regulatory agencies will be consulted and agreement reached on a satisfactory way forward.

ConocoPhillips Alaska, Inc.

WNS DISP Exhibit 7-1 Well Schematic WD-02

Well Attributes

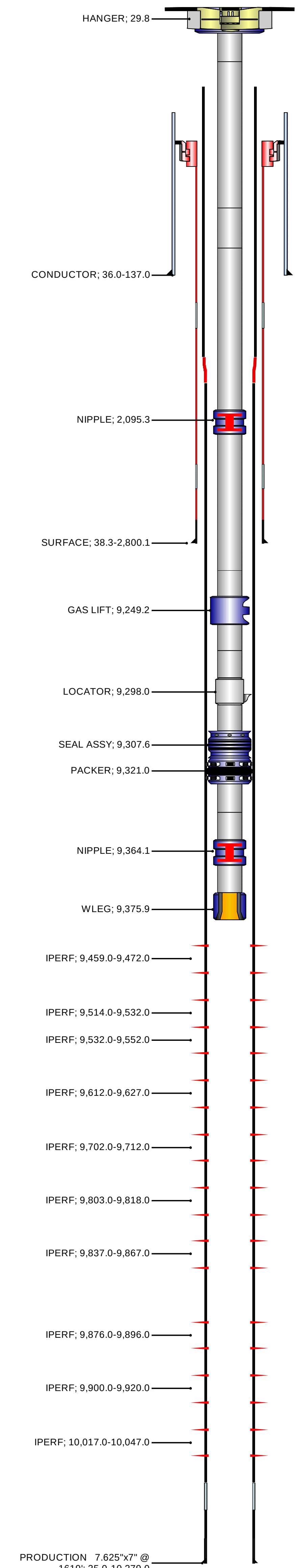
Wellbore API/UWI	Field Name	Wellbore Status	Max Angle & MD: Incl (°)	MD (ftKB)	TD: Act Btm (ftKB)
501032028500	ALPINE	DISP	19.80	5,450.00	10,255.0

Comment	H2S (ppm)	Date	Annotation	End Date	KB-Grd (ft)	Rig Release Date
SSSV: NIPPLE			Last WO:	5/13/2011		4/4/1999

...

WD-02, 3/16/2018 7:55:10 AM

Vertical schematic (actual)



Last Tag

Annotation	Depth (ftKB)	End Date	Last Mod By
Last Tag: RKB	9,871.0	3/4/2018	claytg

Last Rev Reason

Annotation	End Date	Last Mod By
Rev Reason: EPA Compliance Tag	3/4/2018	claytg

Casing Strings

Casing Description	OD (in)	ID (in)	Top (ftKB)	Set Depth (ftKB)	Set Depth (TVD)...	Wt/Len (l...	Grade	Top Thread
CONDUCTOR	16	15.062	36.0	137.0	137.0	62.58	H-40	WELDED
SURFACE	9 5/8	8.921	38.3	2,800.1	2,782.4	36.00	J-55	BTC
PRODUCTION 7.625"x7" @ 1619'	7	6.276	35.0	10,279.0		26.00	L-80	BTCM

Tubing Strings

Tubing Description	String Ma...	ID (in)	Top (ftKB)	Set Depth (ft...	Set Depth (TVD) (...	Wt (lb/ft)	Grade	Top Connection
TUBING	3 1/2	2.992	29.8	9,376.4	9,064.3	9.30	L-80	EUE-M

Completion Details

Top (ftKB)	Top (TVD) (ftKB)	Top Incl (°)	Item Des	Com	Nominal ID (in)
29.8	29.8	0.12	HANGER	FMC TUBING HANGER	3.500
2,095.3	2,077.7	2.39	NIPPLE	CAMCO 'DS' NIPPLE w/2.812 NO GO PROFILE	2.812
9,298.0	8,989.1	16.70	LOCATOR	SEAL ASSEMBLY LOCATOR	3.000
9,307.6	8,998.3	16.64	SEAL ASSY	BAKER 80-40 PBR & SEAL ASSEMBLY w/10' STROKE	4.000
9,321.0	9,011.1	16.57	PACKER	BAKER 47B2 FHL PACKER	3.000
9,364.1	9,052.4	16.29	NIPPLE	HES 'XN' NIPPLE 2.813" PROFILE w/2.75" NO GO	2.750
9,375.9	9,063.8	16.19	WLEG	WIRELINE ENTRY GUIDE	3.000

Perforations & Slots

Top (ftKB)	Btm (ftKB)	Top (TVD) (ftKB)	Btm (TVD) (ftKB)	Zone	Date	Shot Dens (shots/ft)	Type	Com
9,459.0	9,472.0	9,143.8	9,156.3	KNGKD, KNGKE, KNGKF, WD-02	4/9/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,514.0	9,532.0	9,196.8	9,214.1	KNGKD, KNGKE, KNGKF, WD-02	4/9/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,532.0	9,552.0	9,214.1	9,233.3	KNGKD, KNGKE, KNGKF, WD-02	4/8/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,612.0	9,627.0	9,290.8	9,305.2	KNGKD, KNGKE, KNGKF, WD-02	4/8/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,702.0	9,712.0	9,377.2	9,386.8	KNGKD, KNGKE, KNGKF, WD-02	4/8/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,803.0	9,818.0	9,474.3	9,488.8	KNGKD, KNGKE, KNGKF, WD-02	4/8/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,837.0	9,867.0	9,507.1	9,536.1	KNGKD, KNGKE, KNGKF, WD-02	4/7/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,876.0	9,896.0	9,544.8	9,564.1	KNGKD, KNGKE, KNGKF, WD-02	4/7/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
9,900.0	9,920.0	9,567.9	9,587.2	KNGKD, KNGKE, KNGKF, WD-02	4/7/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph
10,017.0	10,047.0	9,681.1	9,710.1	KNGKD, KNGKE, KNGKF, WD-02	4/7/1999	6.0	IPERF	3 3/8 HSD; 60 deg ph

Mandrel Inserts

Stati on N	Top (ftKB)	Top (TVD) (ftKB)	Make	Model	OD (in)	Serv	Valve Type	Latch Type	Port Size (in)	TRO Run (psi)	Run Date	Com
1	9,249.2	8,942.4	CAMCO	KBMG	1	GAS LIFT	DMY	BK	0.000	0.0	4/3/2012	

Notes: General & Safety

End Date	Annotation
4/6/2011	NOTE: View Schematic w/ Alaska Schematic9.0

Exhibit 7-2 AOGCC Completion Report

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION

WELL COMPLETION OR RECOMPLETION REPORT AND LOG

1. Status of well Oil ☐ Gas ☐ Suspended ☐ Abandoned ☐ Service ☑	Classification of Service Well Disposal Well
2. Name of Operator ARCO Alaska, Inc.	7. Permit Number 98-258
3. Address P. O. Box 100360, Anchorage, AK 99510-0360	8. API Number 50-103-20285
4. Location of well at surface 444' FSL, 2052' FEL, Sec. 32, T12N, R5E, UM At Top Producing Interval 161' FSL, 489' FEL, SEC 32, T12N, R5E, UM At Total Depth 85' FSL, 155' FEL, SEC 32, T12N, R5E, UM	9. Unit or Lease Name Colville River Unit 10. Well Number WD-2 11. Field and Pool Colville River Field Alpine Oil Pool
5. Elevation in feet (indicate KB, DF, etc.) DF 57' feet 6. Lease Designation and Serial No. ADL 25558 ALK 4716	

12. Date Spudded	13. Date T.D. Reached	14. Date Comp., Susp. Or Aband.	15. Water Depth, if offshore	16. No. of Completions
March 9, 1999	March 26, 1999	April 4, 1999	N/A feet MSL	1

17. Total Depth (MD + TVD)	18. Plug Back Depth (MD + TVD)	19. Directional Survey	20. Depth where SSSV set	21. Thickness of Permafrost
10255' MD / 9905' TVD	10152' MD / 9805' TVD	YES ☑ No ☐	N/A feet MD	858'

22. Type Electric or Other Logs Run
GR/Res/Neu/Dens, USIT

23. CASING, LINER AND CEMENTING RECORD

CASING SIZE	WT. PER FT.	GRADE	SETTING DEPTH MD TOP	SETTING DEPTH MD BOTTOM	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
16"	62.5#	H-40	Surface	115'	42"	9 cu yds Portland Type III	
9.625"	36#	J-55	Surface	2800'	12.25"	450 sx AS III L, 230 sx Class G	
7.625" x	29.7#	L-80	Surface	1584'	8.5"	1800 sx Class G	
7"	26#	L-80	1584'	10244'	8.5"	(included above)	

24. Perforations open to Production (MD + TVD of Top and Bottom and interval, size and number)

9459'-9472' MD	9137'-9149' TVD	10017'-10047' MD	
9514'-9552' MD	9190'-9226' TVD		9674'-9703' TVD
9612'-9627' MD	9284'-9298' TVD		
9702'-9712' MD	9370'-9380' TVD		
9803'-9818' MD	9467'-9482' TVD		
9837'-9867' MD	9500'-9529' TVD	all 6 spf	
9876'-9896' MD	9538'-9557' TVD		
9900'-9920' MD	9561'-9580' TVD		

25. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
4.5"	7975'	7864'

26. ACID, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT & KIND OF MATERIAL USED
N/A	

27. PRODUCTION TEST

Date First Production	Method of Operation (Flowing, gas lift, etc.)					
	Disposal well					
Date of Test	Hours Tested	Production for Test Period >	OIL-BBL	GAS-MCF	WATER-BBL	CHOKE SIZE / GAS-OIL RATIO
Flow Tubing press. psi	Casing Pressure	Calculated 24-Hour Rate >	OIL-BBL	GAS-MCF	WATER-BBL	OIL GRAVITY - API (corr)

28. CORE DATA

Brief description of lithology, porosity, fractures, apparent dips and pressence of oil, gas or water. Submit core chips.

See Attachment

Form 10-407 Rev. 7-1-80

CONTINUED ON REVERSE SIDE

Submit in duplicate

29. GEOLOGIC MARKERS			30. FORMATION TESTS
NAME	MEAS. DEPTH	TRUE VERT. DEPTH	Include interval tested, pressure data, all fluids recovered and gravity. GOR, and time of each phase.
Top Alpine	7154'	6943'	
Base Alpine	7185'	6973'	
			Annulus left open - freeze protected with diesel.

31. LIST OF ATTACHMENTS
Summary of Daily Operations, Directional Survey

32. I hereby certify that the following is true and correct to the best of my knowledge.

Signed [signature] for. Doug Chester   Title Drilling Team Leader   Date 5-5-99

Prepared by Sharon Allsup-Drake

INSTRUCTIONS

General: This form is designed for submitting a complete and correct well completion report and log on all types of lands and leases in Alaska.

Item 1: Classification of Service wells: Gas injection, water injection, steam injection, air injection, salt water disposal, water supply for injection, observation, injection for in-situ combustion.

Item 5: Indicate which elevation is used as reference (where not otherwise shown) for depth measurements given in other spaces on this form and in any attachments.

Item 16 and 24: If this well is completed for separate production from more than one interval (multiple completion), so state in item 16, and in item 24 show the producing intervals for the interval reported in item 27. Submit a separate form for each additional interval to be separately produced, showing the data pertinent to such interval.

Item 21: Indicate whether from ground level (GL) or other elevation (DF, KB, etc.).

Item 23: Attached supplemental records for this well should show the details of any multiple stage cementing and the location of the cementing tool.

Item 27: Method of Operation: Flowing, Gas Lift, Rod Pump, Hydraulic Pump, Submersible, Water Injection, Gas Injection, Shut-in, Other-explain.

Item 28: If no cores taken, indicate "none".

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION

REPORT OF SUNDRY WELL OPERATIONS

1. Operations Performed: Abandon ☐ Repair well ☐ Plug Perforations ☐ Stimulate ☐ Other ☐
Alter Casing ☐ Pull Tubing ☑ Perforate New Pool ☐ Waiver ☐ Time Extension ☐
Change Approved Program ☐ Operat. Shutdown ☐ Perforate ☐ Re-enter Suspended Well ☐

2. Operator Name: ConocoPhillips Alaska, Inc.

3. Address: P. O. Box 100360, Anchorage, Alaska 99510

4. Well Class Before Work: Development ☐ Exploratory ☐ Stratigraphic ☐ Service ☑

5. Permit to Drill Number: 198-258

6. API Number: 50-103-20285-00

7. Property Designation (Lease Number): ADL 25558

8. Well Name and Number: WD-02

9. Field/Pool(s): Colville River Field / Alpine Oil Pool

10. Present Well Condition Summary:

Total Depth	measured	10255	feet	Plugs (measured)	None
	true vertical	9905	feet	Junk (measured)	None
Effective Depth	measured	10152	feet	Packer (measured)	9321
	true vertical	9805	feet	(true vertucal)	9011

Casing	Length	Size	MD	TVD	Burst	Collapse
CONDUCTOR	102	16	137	137'		
SURFACE	2772	9.625	2800	2782'		
PRODUCTION	1556'	7.625	1584'	1570'		
PRODUCTION	8660'	7"	10244'	9901'		

Perforation depth: Measured depth: from 9459' to 10047'
True Vertical Depth: 9144'-9710'

Tubing (size, grade, MD, and TVD) 3.5, L-80, 9376 MD, 9064 TVD

Packers & SSSV (type, MD, and TVD) PACKER - BAKER FHL @ 9321 MD and 9011 TVD
NIPPLE - CAMCO DS NIPPLE @ 2095 MD and 2078 TVD

11. Stimulation or cement squeeze summary:
Intervals treated (measured): *not applicable*
Treatment descriptions including volumes used and final pressure:

12. Representative Daily Average Production or Injection Data

	Oil-Bbl	Gas-Mcf	Water-Bbl	Casing Pressure	Tubing Pressure
Prior to well operation	not applicable				
Subsequent to operation	not applicable				

13. Attachments
Copies of Logs and Surveys run ____________
Daily Report of Well Operations _____XXX________

14. Well Class after work: Exploratory ☐ Development ☐ Service ☑ Stratigraphic ☐

15. Well Status after work: Oil ☐ Gas ☐ WDSPL ☑
GSTOR ☐ WINJ ☐ WAG ☐ GINJ ☐ SUSP ☐ SPLUG ☐

16. I hereby certify that the foregoing is true and correct to the best of my knowledge.

Sundry Number or N/A if C.O. Exempt: **311-137**

Contact Nina Anderson @ 265-6403
Printed Name Nina Anderson
Title Drilling Engineer
Signature [signature] for Nina Anderson
Phone: 265-6403
Date 6/14/11

Exhibit 7-4 Directional Survey

ConocoPhillips

Directional Survey

WD-02 : 501032028500 : 4/5/2018

MD	TVD	SS	Corr SS	Incline	Azimuth	Dog Leg	X	Y
0	0	58.7	58.7	0	0	0	386661.2	5976560
100	100	-41.3	-41.3	0.41	245.48	0.41	386660.9	5976560
200	200	-141.3	-141.3	0.32	227.56	0.14	386660.3	5976560
300	300	-241.3	-241.3	0.63	254.51	0.37	386659.6	5976560
400	399.99	-341.29	-341.29	0.93	276.51	0.42	386658.2	5976560
500	499.95	-441.25	-441.25	2.19	304.72	1.44	386655.9	5976561
600	599.81	-541.11	-541.11	3.73	313.33	1.6	386652	5976564
700	699.52	-640.82	-640.82	5.02	315.4	1.3	386646.6	5976570
800	799.06	-740.36	-740.36	6.02	319.86	1.09	386640.3	5976577
900	898.36	-839.66	-839.66	7.5	321.73	1.5	386633	5976586
1000	997.22	-938.52	-938.52	9.81	316.73	2.43	386623.3	5976598
1100	1095.44	-1036.74	-1036.74	11.79	313.6	2.06	386610.3	5976611
1200	1193.21	-1134.51	-1134.51	12.43	314.57	0.67	386595.4	5976626
1300	1290.94	-1232.24	-1232.24	12.02	314.81	0.41	386580.6	5976641
1400	1388.89	-1330.19	-1330.19	11.22	315.2	0.8	386566.6	5976655
1500	1486.98	-1428.28	-1428.28	11.2	315.34	0.03	386553.1	5976669
1600	1585.25	-1526.55	-1526.55	10.14	315.87	1.06	386540.3	5976683
1700	1683.91	-1625.21	-1625.21	8.63	316.02	1.51	386529.2	5976695
1800	1783.03	-1724.33	-1724.33	6.52	312.55	2.16	386519.9	5976704
1900	1882.62	-1823.92	-1823.92	3.8	309.31	2.73	386513.3	5976710
2000	1982.47	-1923.77	-1923.77	2.34	307.75	1.46	386509.1	5976714
2100	2082.38	-2023.68	-2023.68	2.39	310.18	0.11	386506	5976716
2200	2182.33	-2123.63	-2123.63	1.16	305.74	1.24	386503.6	5976718
2300	2282.31	-2223.61	-2223.61	0.99	304.17	0.17	386502.1	5976719
2400	2382.29	-2323.59	-2323.59	1.01	305.53	0.03	386500.7	5976720
2500	2482.27	-2423.57	-2423.57	1.07	295.44	0.19	386499.1	5976721
2600	2582.25	-2523.55	-2523.55	0.96	304.21	0.19	386497.6	5976722
2700	2682.23	-2623.53	-2623.53	1.06	306.37	0.11	386496.2	5976723
2800	2782.21	-2723.51	-2723.51	1.01	306.09	0.05	386494.7	5976724
2900	2882.2	-2823.5	-2823.5	0.9	306.62	0.11	386493.4	5976725
3000	2982.19	-2923.49	-2923.49	0.83	59.27	1.44	386493.4	5976726
3050	3032.16	-2973.46	-2973.46	3.22	87.84	5.04	386495.1	5976726
3100	3082.03	-3023.33	-3023.33	5.12	89.96	3.81	386498.8	5976726
3150	3131.75	-3073.05	-3073.05	6.92	95.25	3.76	386504	5976726
3200	3181.33	-3122.63	-3122.63	8.02	97.86	2.3	386510.4	5976725
3250	3230.79	-3172.09	-3172.09	8.76	97.37	1.49	386517.6	5976724
3300	3280.13	-3221.43	-3221.43	9.9	98.99	2.34	386525.6	5976723

Exhibit 7-4 Directional Survey

ConocoPhillips

Directional Survey

WD-02 : 501032028500 : 4/5/2018

MD	TVD	SS	Corr SS	Incline	Azimuth	Dog Leg	X	Y
3400	3378.07	-3319.37	-3319.37	13.39	111.35	4.27	386544.8	5976717
3450	3426.61	-3367.91	-3367.91	14.32	112.91	2	386555.9	5976712
3500	3475.03	-3416.33	-3416.33	14.59	113.04	0.54	386567.3	5976707
3550	3523.38	-3464.68	-3464.68	14.9	112.8	0.63	386578.9	5976702
3600	3571.64	-3512.94	-3512.94	15.44	111.97	1.16	386590.9	5976697
3650	3619.76	-3561.06	-3561.06	16.04	111.08	1.29	386603.5	5976692
3700	3667.77	-3609.07	-3609.07	16.41	110.74	0.76	386616.5	5976687
3750	3715.69	-3656.99	-3656.99	16.76	110.24	0.76	386629.7	5976681
3800	3763.51	-3704.81	-3704.81	17.21	109.29	1.06	386643.4	5976676
3850	3811.25	-3752.55	-3752.55	17.39	108.81	0.46	386657.4	5976671
3900	3858.95	-3800.25	-3800.25	17.49	108.51	0.27	386671.5	5976666
3950	3906.61	-3847.91	-3847.91	17.67	108.1	0.44	386685.8	5976661
4000	3954.22	-3895.52	-3895.52	17.89	107.51	0.57	386700.2	5976656
4050	4001.78	-3943.08	-3943.08	18.06	107.13	0.41	386714.9	5976651
4100	4049.34	-3990.64	-3990.64	17.91	106.33	0.58	386729.6	5976647
4150	4096.9	-4038.2	-4038.2	18	106.01	0.27	386744.4	5976642
4200	4144.45	-4085.75	-4085.75	18.04	105.9	0.11	386759.2	5976638
4250	4191.96	-4133.26	-4133.26	18.24	105.87	0.4	386774.1	5976633
4300	4239.44	-4180.74	-4180.74	18.26	105.81	0.05	386789.1	5976629
4350	4286.89	-4228.19	-4228.19	18.51	105.73	0.5	386804.2	5976624
4400	4334.31	-4275.61	-4275.61	18.49	105.41	0.21	386819.4	5976620
4450	4381.74	-4323.04	-4323.04	18.41	104.81	0.41	386834.6	5976615
4500	4429.21	-4370.51	-4370.51	18.23	104.37	0.45	386849.8	5976611
4550	4476.73	-4418.03	-4418.03	18.04	103.78	0.53	386864.8	5976607
4600	4524.26	-4465.56	-4465.56	18.1	103.44	0.24	386879.8	5976603
4650	4571.76	-4513.06	-4513.06	18.27	103.4	0.34	386894.9	5976600
4700	4619.22	-4560.52	-4560.52	18.38	103.24	0.24	386910.2	5976596
4750	4666.67	-4607.97	-4607.97	18.35	103.2	0.07	386925.5	5976592
4800	4714.13	-4655.43	-4655.43	18.32	102.81	0.25	386940.7	5976588
4850	4761.6	-4702.9	-4702.9	18.32	102.56	0.16	386956	5976584
4900	4809.06	-4750.36	-4750.36	18.35	102.19	0.24	386971.3	5976581
4950	4856.5	-4797.8	-4797.8	18.47	101.75	0.37	386986.7	5976577
5000	4903.93	-4845.23	-4845.23	18.44	101.52	0.16	387002.2	5976574
5050	4951.37	-4892.67	-4892.67	18.38	101.25	0.21	387017.6	5976571
5100	4998.85	-4940.15	-4940.15	18.18	100.97	0.44	387032.9	5976567
5150	5046.38	-4987.68	-4987.68	18.02	100.99	0.32	387048.1	5976564
5200	5093.88	-5035.18	-5035.18	18.36	101.54	0.76	387063.4	5976561

Exhibit 7-4 Directional Survey

ConocoPhillips

Directional Survey

WD-02 : 501032028500 : 4/5/2018

MD	TVD	SS	Corr SS	Incline	Azimuth	Dog Leg	X	Y
5250	5141.27	-5082.57	-5082.57	18.86	101.98	1.04	387079	5976557
5300	5188.6	-5129.9	-5129.9	18.74	101.44	0.42	387094.7	5976554
5350	5235.9	-5177.2	-5177.2	19.07	103.13	1.28	387110.5	5976550
5400	5283.07	-5224.37	-5224.37	19.71	106.88	2.8	387126.4	5976546
5450	5330.13	-5271.43	-5271.43	19.8	106.93	0.18	387142.5	5976540
5500	5377.22	-5318.52	-5318.52	19.48	106.69	0.66	387158.5	5976535
5550	5424.39	-5365.69	-5365.69	19.29	106.45	0.41	387174.4	5976530
5600	5471.62	-5412.92	-5412.92	19.05	106.17	0.51	387190	5976525
5650	5518.93	-5460.23	-5460.23	18.69	105.85	0.75	387205.5	5976521
5700	5566.32	-5507.62	-5507.62	18.5	105.63	0.41	387220.8	5976516
5750	5613.77	-5555.07	-5555.07	18.27	105.36	0.49	387235.9	5976512
5800	5661.28	-5602.58	-5602.58	18.06	105.45	0.42	387250.9	5976507
5850	5708.82	-5650.12	-5650.12	18.07	105.39	0.04	387265.8	5976503
5900	5756.37	-5697.67	-5697.67	17.94	105.65	0.31	387280.6	5976499
5950	5803.94	-5745.24	-5745.24	17.94	105.76	0.07	387295.4	5976494
6000	5851.49	-5792.79	-5792.79	18.1	105.65	0.33	387310.2	5976490
6050	5899.02	-5840.32	-5840.32	18.07	105.79	0.11	387325.1	5976485
6100	5946.57	-5887.87	-5887.87	17.94	105.53	0.31	387339.9	5976481
6150	5994.16	-5935.46	-5935.46	17.76	105.33	0.38	387354.6	5976477
6200	6041.8	-5983.1	-5983.1	17.6	104.76	0.47	387369.2	5976473
6250	6089.42	-6030.72	-6030.72	17.92	104.84	0.64	387383.9	5976468
6300	6137.01	-6078.31	-6078.31	17.82	104.49	0.29	387398.7	5976464
6350	6184.61	-6125.91	-6125.91	17.82	104.27	0.13	387413.4	5976460
6400	6232.22	-6173.52	-6173.52	17.74	103.81	0.32	387428.2	5976456
6450	6279.78	-6221.08	-6221.08	18.17	103.85	0.86	387443.1	5976453
6500	6327.24	-6268.54	-6268.54	18.52	103.59	0.72	387458.3	5976449
6550	6374.62	-6315.92	-6315.92	18.75	103.74	0.47	387473.8	5976445
6600	6421.95	-6363.25	-6363.25	18.86	103.32	0.35	387489.4	5976441
6650	6469.29	-6410.59	-6410.59	18.69	103.26	0.34	387505	5976437
6700	6516.69	-6457.99	-6457.99	18.46	104.09	0.7	387520.4	5976433
6750	6564.09	-6505.39	-6505.39	18.68	104.99	0.72	387535.8	5976428
6800	6611.49	-6552.79	-6552.79	18.46	106.08	0.82	387551	5976424
6850	6658.96	-6600.26	-6600.26	18.18	105.7	0.61	387566.1	5976419
6900	6706.52	-6647.82	-6647.82	17.75	105.63	0.86	387580.9	5976415
6950	6754.14	-6695.44	-6695.44	17.73	105.12	0.31	387595.5	5976411
7000	6801.77	-6743.07	-6743.07	17.69	104.95	0.13	387610.1	5976407
7050	6849.38	-6790.68	-6790.68	17.91	104.66	0.47	387624.8	5976402

Exhibit 7-4 Directional Survey

ConocoPhillips

Directional Survey

WD-02 : 501032028500 : 4/5/2018

MD	TVD	SS	Corr SS	Incline	Azimuth	Dog Leg	X	Y
7100	6896.91	-6838.21	-6838.21	18.26	104.94	0.72	387639.8	5976398
7150	6944.34	-6885.64	-6885.64	18.62	103.9	0.98	387655	5976394
7200	6991.73	-6933.03	-6933.03	18.58	104.2	0.21	387670.5	5976390
7250	7039.13	-6980.43	-6980.43	18.51	103.54	0.44	387685.8	5976386
7300	7086.55	-7027.85	-7027.85	18.47	103.58	0.08	387701.2	5976382
7350	7133.98	-7075.28	-7075.28	18.41	103.31	0.21	387716.5	5976378
7400	7181.42	-7122.72	-7122.72	18.43	105.12	1.14	387731.8	5976374
7450	7228.85	-7170.15	-7170.15	18.46	106.5	0.88	387746.9	5976369
7500	7276.31	-7217.61	-7217.61	18.21	105.78	0.67	387762	5976365
7550	7323.84	-7265.14	-7265.14	17.93	106.02	0.58	387776.8	5976360
7600	7371.42	-7312.72	-7312.72	17.84	105.45	0.39	387791.5	5976356
7650	7419.05	-7360.35	-7360.35	17.57	106.02	0.64	387806.1	5976352
7700	7466.73	-7408.03	-7408.03	17.46	107.08	0.67	387820.5	5976347
7750	7514.43	-7455.73	-7455.73	17.47	106.17	0.55	387834.8	5976343
7800	7562.1	-7503.4	-7503.4	17.64	105.72	0.44	387849.2	5976338
7850	7609.71	-7551.01	-7551.01	17.9	105.49	0.54	387863.8	5976334
7900	7657.29	-7598.59	-7598.59	17.91	104.99	0.31	387878.6	5976330
7950	7704.86	-7646.16	-7646.16	17.95	105.01	0.08	387893.4	5976325
8000	7752.41	-7693.71	-7693.71	18.1	104.82	0.32	387908.3	5976321
8050	7799.98	-7741.28	-7741.28	17.75	105.4	0.79	387923.1	5976317
8100	7847.63	-7788.93	-7788.93	17.5	104.96	0.57	387937.6	5976313
8150	7895.31	-7836.61	-7836.61	17.53	105.05	0.08	387952.1	5976309
8200	7942.99	-7884.29	-7884.29	17.52	105.08	0.03	387966.6	5976305
8250	7990.64	-7931.94	-7931.94	17.78	105.29	0.54	387981.2	5976300
8300	8038.22	-7979.52	-7979.52	18.03	105.37	0.5	387995.9	5976296
8350	8085.74	-8027.04	-8027.04	18.19	105.61	0.35	388010.8	5976292
8400	8133.28	-8074.58	-8074.58	17.91	105.75	0.57	388025.7	5976287
8450	8180.9	-8122.2	-8122.2	17.58	105.3	0.71	388040.3	5976283
8500	8228.56	-8169.86	-8169.86	17.63	104.99	0.21	388054.8	5976279
8550	8276.19	-8217.49	-8217.49	17.81	104.7	0.4	388069.5	5976275
8600	8323.84	-8265.14	-8265.14	17.49	104.63	0.64	388084.1	5976271
8650	8371.57	-8312.87	-8312.87	17.17	104.72	0.64	388098.5	5976267
8700	8419.38	-8360.68	-8360.68	16.88	104.44	0.6	388112.6	5976263
8750	8467.19	-8408.49	-8408.49	17.15	104.55	0.54	388126.7	5976259
8800	8514.92	-8456.22	-8456.22	17.5	104.2	0.73	388141	5976255
8850	8562.53	-8503.83	-8503.83	18.09	105.02	1.28	388155.8	5976251
8900	8610.03	-8551.33	-8551.33	18.3	104.89	0.43	388170.8	5976247

Exhibit 7-4 Directional Survey

ConocoPhillips

Directional Survey

WD-02 : 501032028500 : 4/5/2018

MD	TVD	SS	Corr SS	Incline	Azimuth	Dog Leg	X	Y
8950	8657.55	-8598.85	-8598.85	17.93	105.26	0.77	388185.7	5976242
9000	8705.14	-8646.44	-8646.44	17.83	104.79	0.35	388200.5	5976238
9050	8752.69	-8693.99	-8693.99	18.16	104.4	0.7	388215.4	5976234
9100	8800.2	-8741.5	-8741.5	18.15	104.13	0.17	388230.4	5976230
9150	8847.75	-8789.05	-8789.05	17.84	103.89	0.64	388245.4	5976226
9200	8895.39	-8836.69	-8836.69	17.51	103.71	0.67	388260	5976222
9250	8943.13	-8884.43	-8884.43	17.07	103.78	0.88	388274.4	5976218
9300	8990.98	-8932.28	-8932.28	16.68	103.61	0.79	388288.5	5976215
9350	9038.91	-8980.21	-8980.21	16.41	103.99	0.58	388302.2	5976211
9400	9086.92	-9028.22	-9028.22	15.99	104.84	0.96	388315.7	5976207
9450	9135.05	-9076.35	-9076.35	15.44	105.21	1.12	388328.7	5976204
9500	9183.27	-9124.57	-9124.57	15.23	105.23	0.42	388341.4	5976200
9550	9231.35	-9172.65	-9172.65	16.64	103.8	2.93	388354.7	5976196
9600	9279.25	-9220.55	-9220.55	16.66	102.92	0.51	388368.6	5976193
9650	9327.2	-9268.5	-9268.5	16.3	103.24	0.74	388382.3	5976190
9700	9375.21	-9316.51	-9316.51	16.16	103.14	0.29	388395.9	5976186
9750	9423.28	-9364.58	-9364.58	15.78	103.21	0.76	388409.2	5976183
9800	9471.43	-9412.73	-9412.73	15.47	103.35	0.62	388422.3	5976179
9850	9519.64	-9460.94	-9460.94	15.27	103.68	0.44	388435.1	5976176
9900	9567.9	-9509.2	-9509.2	15.07	103.53	0.41	388447.8	5976173
9950	9616.21	-9557.51	-9557.51	14.8	103.7	0.55	388460.3	5976170
10000	9664.57	-9605.87	-9605.87	14.61	104	0.41	388472.5	5976166
10050	9712.98	-9654.28	-9654.28	14.39	103.77	0.45	388484.6	5976163
10100	9761.43	-9702.73	-9702.73	14.25	103.87	0.28	388496.6	5976160
10148	9807.98	-9749.28	-9749.28	13.96	102.76	0.83	388508	5976157
10255	9911.82	-9853.12	-9853.12	13.96	102.76	0	388533	5976151

174 records retrieved for Directional Survey

Exhibit 7-5 Well Abandonment Plan Outline

Final Well Abandonment Plan

Abandonment plans for waste disposal wells will be implemented in accordance with the following procedures. At the time of final abandonment, these plans will be revised to reflect the current State of Alaska Oil and Gas Conservation Commission regulatory requirements and/or current EPA regulations, as well as utilizing current technology applicable to the condition of the well at this time. These agencies will be notified in sufficient time to witness the abandonment operation. Approvals will be obtained via AOGCC Form 10-403 and EPA Form 7520-14.

Abandonment Procedure

1. Pressure test tubing by 7” casing annulus.
2. Rig up slickline unit to gauge tubing & tag bottom.
3. Rig up coiled tubing unit and pressure test BOP. If deemed necessary, perform fill cleanout to expose perforated intervals. Establish circulation and lay in cement across the perforated intervals. Pull up into tubing, circulate clean and down squeeze cement. Well should be loaded with adequate kill weight fluid in tubing and inner annulus prior to setting cement. Density of kill weight fluid to be modified to account for bottom-hole pressure at time of abandonment.
4. Allow for cement to cure. Tag top of cement.
5. Set mechanical bridge plug in tubing at +/-1000’ MD.
6. Use tubing punch to shoot holes in tubing above the bridge plug.
7. Establish circulation down tubing, taking returns from 7” casing valve. Fill tubing and annular space with cement.
8. After allowing cement to cure, perform combo tubing with inner annulus drawdown test.
9. Rig up on 9-5/8” by 7” casing annulus valves, pumping target volume based on annular capacity to achieve minimum of 150’ of cement column in OA.
10. Perform outer annulus drawdown test.
11. Excavate wellhead, cut off all casing/tubing strings below ground level and weld on metal cover.
12. Rig down equipment and reclaim location.

Exhibit 7-6 EPA 7520-14 P&A Form

OMB No. 2040-0042 Approval Expires 12/31/2018

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Colville Delta No. 1 (CD1) Pad Colville River Unit	ConocoPhillips Alaska, Inc. P.O. Box 100360; 700 G. Street, Anchorage, AK 99501

Locate Well and Outline Unit on Section Plat - 640 Acres

N
W E
S

State	County	Permit Number
Alaska	North Slope	AK-1I003-B

Surface Location Description

____ 1/4 of SW 1/4 of SW 1/4 of ____ 1/4 of Section 32 Township 12N Range 5E

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ____ ft. frm (N/S) ____ Line of quarter section
and ____ ft. from (E/W) ____ Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name ADL025558

WELL ACTIVITY

- [x] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number WD-02

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
3-1/2"	9.3		9376	
7"	26		8660	
7-5/8"	29.7		1619	
9-5/8"	36		2782	

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [ ] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [x] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	3-1/2"	7"					
Depth to Bottom of Tubing or Drill Pipe (ft	9,376	10,279					
Sacks of Cement To Be Used (each plug)	-	-					
Slurry Volume To Be Pumped (cu. ft.)	-	-					
Calculated Top of Plug (ft.)							
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	TBD	TBD					
Type Cement or Other Material (Class III)	Class G	Class G					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
9459	9472	9803	9818
9514	9552	9837	9867
9612	9627	9876	9896
9702	9712	9900, 10017	9920, 10047

Estimated Cost to Plug Wells

$650M

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed

EPA Form 7520-14 (Rev. 12-11)

WD-02 Well Completion Summary Report

Overview – Well WD-2 was completed for injection on April 9, 1999 upon conclusion of perforating.

Well Status – SI pending start-up of surface facilites.

Key Dates – The Doyon 19 rig made it in off the ice road on March 8, after difficulties breaking through the sea ice. The rig was accepted and the well was spudded at 1000 hrs on March 9. The rig was released at 0100 hrs on April 6. This is the first well drilled in the 1999 drilling season. Upon completion of WD-2, the rig moved onto the drilling pad to drill well 1-19.

Surface casing – The 9-5/8" casing was set 10' off bottom (2810'), at 2800' MD on March 13. Openhole logs were run to TD to satisfy permit requirements. The caliper indicated several washed out intervals, and for that reason late adjustments were made in the cement volumes. Cement returns were received at the surface.

Production casing –The 7" casing was set on bottom at 10,244. TD was slightly deeper at 10,255'. Openhole logging was unsuccessful in reaching TD. Our goal was to log the entire interval for an area reference, but ledges and washouts prevented getting tools to bottom. After tools hung following a reaming pass, logging was halted. Cementing was adjusted per the caliper, which reached the Sag River. The additional cement paid dividends since there were problems losing circulation while cementing, and when the plug bumped early fluid fell back in the annulus. In spite of this, top of cement was clearly seen to 6400' MD, with additional proper cement bond up to 6000'MD. Target TOC was 6500'MD.

Cementing – Excellent results seen on both USIT logs run, due to the extra efforts on the drillers and cementers.

Completion interval – The Sadlerochit was drilled in good order. Gross sand from 9066'-9727'TVDSS is 661', but only 127' TVD is pay quality (+13% porosity). The Sag River extends from 8580'-8619' TVDSS, for 39' gross. Net height is only 35' of quality pay sand. All intervals in the lower Sadlerochit with high sonic porosity and low resistivity were shot, 191' in all. The Sag River was not shot at this time to provide an opportunity to adperf later as needed. It is the banked resource should injection fluids ever irreparairably damage the Ivishak. The packer was set intentionally in the base of the Upper Kingak Shale to allow full logging across the Lower Kingak Shale to satisfy the EPA. Our permit allows us to fracture and push injection fluids out of the disposal interval and up into the Arresting Interval (Lower Kingak).

Bottomhole Pressures – The Lee Tool survey of 4/11/99 stopped at mid-perfs of 9,753' MD/9,361' TVDSS and measured 4,596 psig. This is a gradient of 9.44 psi/ft. Bottomhole temperature at that depth was measured to be 222°F.

Initial Injection Rates – A step rate test was conducted on 4/11/99 for the EPA to determine fracture gradient. The fracture pressure was determined to be 1,984 psi WHP aat a rate of 1.38 BPM (1987 BPD). This corresponds to a formation fracture pressure of 6,259 psi, a fracture gradient of 0.66 psi/ft. This fracture gradient matches the most common fracture gradient seen in the Sadlerochit Formation in the Prudhoe Bay Field. The step rate test was conducted with 8.5 ppg winter SW sourced at CPF-3, and was heated to approximately 150°F. The maximum injection rate reached during the brief test was 15 BPM at approximately 3200 psi.

Exhibit 7-7 Construction and Completion Reports
WD-02 Daily Drilling Reports

Date	From	To	Duration	Start Depth	End Depth	Activity
3/9/1999 0:00	6:00	7:00	1	0	528	PJSM=Making up stds. of 5"" dp. & stand back.
3/9/1999 0:00	7:00	9:00	2	528	528	Adjust top drive track dolly. Check all equip. Pre spud list=Pre job meeting.
3/9/1999 0:00	9:00	10:00	1	528	528	Pick up BHA #1.
3/9/1999 0:00	10:00	11:00	1	528	528	Fill hole=check for leaks=check diverter conns.
3/9/1999 0:00	11:00	15:00	4	528	528	Drlg. w/ hwdp f/ 115 to 278'.
3/9/1999 0:00	15:00	18:00	3	528	528	Stand back 2 stds. hwdp=pick up monel dc,s.
3/9/1999 0:00	18:00	18:30	0.5	528	528	PJSM on making conn,s.
3/9/1999 0:00	18:30	0:00	5.5	528	528	Drlg. f/ 278' to 528'.
3/10/1999 0:00	0:00	15:00	15	528	1970	Drlg. & surveys f/ 528' to 1535'.
3/10/1999 0:00	15:00	15:30	0.5	1970	1970	Circ. hole clean.
3/10/1999 0:00	15:30	18:00	2.5	1970	1970	Wiper Trip to 173'.=(hole in good condition).
3/10/1999 0:00	18:00	18:30	0.5	1970	1970	PJSM=Topic=Shoveling snow off rig.
3/10/1999 0:00	18:30	0:00	5.5	1970	1970	Drlg. & Surveys f/ 1535' to 1970'.
3/11/1999 0:00	0:00	14:00	14	1970	2810	Drlg. & surveys f/1970 to 2810'.
3/11/1999 0:00	14:00	15:00	1	2810	2810	Circ. hole clean w/ hi-vis sweep.
3/11/1999 0:00	15:00	17:00	2	2810	2810	Wiper trip to 1414'=no hole problems.
3/11/1999 0:00	17:00	18:00	1	2810	2810	CBU.
3/11/1999 0:00	18:00	18:30	0.5	2810	2810	PJSM on Handling bha.
3/11/1999 0:00	18:30	22:30	4	2810	2810	POH=lay down motor & mwd.
3/11/1999 0:00	22:30	23:00	0.5	2810	2810	Clear floor & ser. rig.
3/11/1999 0:00	23:00	0:00	1	2810	2810	Rig up sws & hold safety meeting on wl work.
3/12/1999 0:00	0:00	6:00	6	2810	2810	Run Platform express & 4 arm caliper as per program w/ sws.
3/12/1999 0:00	6:00	6:30	0.5	2810	2810	PJSM=Topic=drills.
3/12/1999 0:00	6:30	9:30	3	2810	2810	Finish running 4 arm caliper. Rig down sws.
3/12/1999 0:00	9:30	10:30	1	2810	2810	Make up bha.
3/12/1999 0:00	10:30	11:30	1	2810	2810	Rih to 2810.
3/12/1999 0:00	11:30	13:00	1.5	2810	2810	Cbu.=reciprocate & rotate.
3/12/1999 0:00	13:00	15:00	2	2810	2810	Poh to run 9 5/8"" csg.
3/12/1999 0:00	15:00	16:30	1.5	2810	2810	Lay down bha & clear floor.
3/12/1999 0:00	16:30	0:00	7.5	2810	2810	PJSM=r/u & run 65 jts. 9 5/8"" 36# J-55 buttress csg.
3/13/1999 0:00	0:00	1:00	1	2810	2810	Finish running 65 jts. 9 5/8"" 36# J-55 csg.
3/13/1999 0:00	1:00	2:00	1	2810	2810	R/D csg. fill up tool=blow down top drive=m/u landing jt.=land csg. @ 2800'=install cementing head.
3/13/1999 0:00	2:00	3:30	1.5	2810	2810	Break circ.=stage circ. rate f/ 2 bpm to 10 bpm=circ. while preping dowell f/ cement job.
3/13/1999 0:00	3:30	6:30	3	2810	2810	PJSM w/ all hands on cementing procedures=Test lines to 2500#=Cement well as per program=full circ. thru out job=reciprocate pipe thru out job. Bumped plug on calculated strokes=recovered 69 bbl. cement returns @ 10.8#.
3/13/1999 0:00	6:30	9:00	2.5	2810	2810	Wash out riser=work & wash out annular preventer=l/d cement head-landing jt. & csg. equipment.
3/13/1999 0:00	9:00	12:30	3.5	2810	2810	N/d flowline=riser=diverter line=annular preventer=etc.
3/13/1999 0:00	12:30	18:00	5.5	2810	2810	N/u bop,s=riser=flowline & shorten riser.
3/13/1999 0:00	18:00	0:00	6	2810	2810	Pick up riser & test plug=test bope & choke manifold 250-4000#.
3/14/1999 0:00	0:00	1:30	1.5	2810	3091	Finish testing bope=pull test plug & set wear bushing.
3/14/1999 0:00	1:30	2:00	0.5	3091	3091	Install bails & elevators=load floor w/ bha#3.
3/14/1999 0:00	2:00	6:00	4	3091	3091	Pick up & make up bha#3=Program & install sources in mwd.
3/14/1999 0:00	6:00	6:30	0.5	3091	3091	PJSM=service rig.
3/14/1999 0:00	6:30	7:00	0.5	3091	3091	RIH to 1095'.
3/14/1999 0:00	7:00	9:30	2.5	3091	3091	Slip & cut drlg. line=install new stop on end of drlg. line.
3/14/1999 0:00	9:30	11:00	1.5	3091	3091	Rih picking up 5"" dp to 2049'=shallow test mwd.
3/14/1999 0:00	11:00	14:00	3	3091	3091	PJSM=Stripping drill w/ all hands.
3/14/1999 0:00	14:00	15:00	1	3091	3091	Rig up & test csg. to 2500# 30 mins. ok=blow down lines.

Exhibit 7-7 Construction and Completion Reports
WD-02 Daily Drilling Reports

Date	From	To	Duration	Start Depth	End Depth	Activity
3/14/1999 0:00	15:00	15:30	0.5	3091	3091	Change breaker in SCR. No comment. Rig maintenance.
3/14/1999 0:00	15:30	16:00	0.5	3091	3091	Single in hole to 2712'.
3/14/1999 0:00	16:00	16:30	0.5	3091	3091	Circ. out contaminated mud.
3/14/1999 0:00	16:30	18:00	1.5	3091	3091	Drill plugs=float collar=cement=shoe & 20' new hole f/ 2810 to 2830.
3/14/1999 0:00	18:00	20:00	2	3091	3091	Circ.-condition mud f/ lot.
3/14/1999 0:00	20:00	21:00	1	3091	3091	Perform lot=emw-14.4.=blow down lines.
3/14/1999 0:00	21:00	0:00	3	3091	3091	Drlg. & surveys f/ 2830 to 3091.
3/15/1999 0:00	0:00	0:00	24	3091	5093	Drlg. & surveys f/ 3091 to 5093'.
3/16/1999 0:00	0:00	2:30	2.5	5093	6523	Drlg. & Surveys to 5281'.
3/16/1999 0:00	2:30	3:30	1	6523	6523	CBU=clean hole..
3/16/1999 0:00	3:30	8:30	5	6523	6523	Wiper trip to 9 5/8"" shoe=Tight f/ 4430 to 4110'. (pulled 50k over string wt.)
3/16/1999 0:00	8:30	0:00	15.5	6523	6523	Drlg. & surveys f/ 5281 to 6523'.
3/17/1999 0:00	0:00	21:30	21.5	6523	7756	Drlg f/ 6523' to 7756'. ADT - 14.75 hrs
3/17/1999 0:00	21:30	22:30	1	7756	7756	Pump sweep. Circ and cond mud for wipertrip.
3/17/1999 0:00	22:30	0:00	1.5	7756	7756	POH. Tight at 6637 to 6429. Worked through OK. Pulled 50k over.
3/18/1999 0:00	0:00	1:00	1	7756	8159	Work through tight hole at 6429'.
3/18/1999 0:00	1:00	5:00	4	8159	8159	Pump and back ream from 6429' to 6141'. Cont' POH. Intermittent tight hole from 6141' to 5329'. Needed to back ream through the HRZ shale which had been open for +/- 30 hours. 2 trips required but hole slick after second trip. No problems with HRZ thereafter. Wipe HRZ within 24 hours of drilling.
3/18/1999 0:00	5:00	6:00	1	8159	8159	RIH to TD. No problems. Time associated with above problem. N/A
3/18/1999 0:00	6:00	7:30	1.5	8159	8159	Circ, rotate and reciprocate. Pump sweep. Had fair amount of large (soft) rounded shale. Small amount of splintered shale. Circ hole clean. Associated with above. Some of the returns believed to be caused by mechanical action of drill pipe against the side of the hole while working pipe during circulation. Not necessary to reciprocate and rotate the pipe to the same degree in a low angle hole. For the development wells increased mud weight (i.e. 9.8 ppg - 10 ppg) may assist.
3/18/1999 0:00	7:30	10:00	2.5	8159	8159	POH to 5329'. No problems. No overpull. Tight at 5329. Circ and backream to 5240'. POH to 5095'. No problems. Associated with above. As per above.
3/18/1999 0:00	10:00	12:00	2	8159	8159	RIH while PU singles.
3/18/1999 0:00	12:00	12:30	0.5	8159	8159	CBU. No gas or oil cut mud.
3/18/1999 0:00	12:30	0:00	11.5	8159	8159	Drlg f/ 7756' to 8159'. ADT - 9.5 hrs
3/19/1999 0:00	0:00	21:00	21	8159	8992	Drlg f/ 8159' to 8992'. Had some problems sliding. Drill pipe wt would slip and stall motor. Adding soap and lubricants.
3/19/1999 0:00	21:00	22:00	1	8992	8992	Circ sweep. Monitor well. blow down.
3/19/1999 0:00	22:00	0:00	2	8992	8992	Wiper trip to 7569'. No problems.
3/20/1999 0:00	0:00	0:30	0.5	8992	9275	Finish wiper trip. No problems.
3/20/1999 0:00	0:30	1:30	1	9275	9275	CBU. No gas or oil cut mud. No fill.
3/20/1999 0:00	1:30	12:00	10.5	9275	9275	Drlg f/ 8992' to 9275'. PR slowed to 7' per hr.
3/20/1999 0:00	12:00	13:00	1	9275	9275	Pump sweep. Some splintered shale in returns.
3/20/1999 0:00	13:00	13:30	0.5	9275	9275	Monitor well. Static. Pump slug. Blow down top drive.
3/20/1999 0:00	13:30	17:00	3.5	9275	9275	POH to 3134. Tight. 50 k over wt.
3/20/1999 0:00	17:00	18:30	1.5	9275	9275	Back ream and circ f/ 3134' to 3096'. Cleaning up shales that had been open for +5 days. Review required wiper trip frequency. These shales will be wiped during the 8-1/2 in. BHA change in the development wells.
3/20/1999 0:00	18:30	20:30	2	9275	9275	POH. Monitor well at shoe. Static.
3/20/1999 0:00	20:30	22:00	1.5	9275	9275	Set back 1 std DC's. Remove source. Download MWD.
3/20/1999 0:00	22:00	22:30	0.5	9275	9275	POH. Drain and check motor. Change bits.
3/20/1999 0:00	22:30	23:30	1	9275	9275	Program MWD tools. Load source. MU DC's.
3/20/1999 0:00	23:30	0:00	0.5	9275	9275	RIH to 1192'.
3/21/1999 0:00	0:00	0:30	0.5	9275	9477	Shallow test MWD. Blow down top drive.
3/21/1999 0:00	0:30	6:00	5.5	9477	9477	RIH to 9093'. Fill pipe each 25 stds. No problems.
3/21/1999 0:00	6:00	7:30	1.5	9477	9477	Mad pass f/ 9093' to 9275' for log tie in.

Exhibit 7-7 Construction and Completion Reports
WD-02 Daily Drilling Reports

Date	From	To	Duration	Start Depth	End Depth	Activity
3/21/1999 0:00	7:30	0:00	16.5	9477	9477	Drlg f/ 9275' to 9477'. ADT - 13.5 hrs.
3/22/1999 0:00	0:00	0:00	24	9477	9683	Drlg f/ 9477' to 9589'. ADT - 20.9 hrs. Shale sections drlg at
3/23/1999 0:00	17:30	18:30	1	9747	9747	Pull wear bushing. Packed with clay and sand.
3/23/1999 0:00	18:30	23:00	4.5	9747	9747	Test BOPE to 300-4000 psi w/ annular to 2500 psi. Witness of test waived by AOGCC rep Larry Wade.
3/23/1999 0:00	23:00	0:00	1	9747	9747	RD test equipment. Install wear bushing.
3/24/1999 0:00	0:00	2:30	2.5	9747	9854	Change motors. MU MWD tools. Load source.
3/24/1999 0:00	2:30	4:00	1.5	9854	9854	RIH to 2717'.
3/24/1999 0:00	4:00	6:00	2	9854	9854	Cut and slip drlg line. Service rig and top drive.
3/24/1999 0:00	6:00	10:00	4	9854	9854	RIH to 9570' Fill pipe every 25 stds. No problems.
3/24/1999 0:00	10:00	12:30	2.5	9854	9854	Ream f/ 9570' to 9747'.
3/24/1999 0:00	12:30	0:00	11.5	9854	9854	Drlg f/ 9747' to 9854'. ADT - 10.4 hrs. PR 7-35 fph.
3/25/1999 0:00	0:00	0:00	24	9854	10210	Drlg f/ 9854' to 10,210'. ADT - 22.6 hrs.
3/26/1999 0:00	0:00	4:00	4	10210	10255	Drilled f/ 10,210' to 10,255' ADT = 3.7 hrs.
3/26/1999 0:00	4:00	5:30	1.5	10255	10255	Circulate HiVis sweep
3/26/1999 0:00	5:30	6:00	0.5	10255	10255	Monitor well, blow down top drive.
3/26/1999 0:00	6:00	7:30	1.5	10255	10255	POH. Tight @ 9800'. Back ream to 9476'.
3/26/1999 0:00	7:30	9:00	1.5	10255	10255	Circ bottoms up. Additional circulation required to help clear up tight hole in the Ivishak. Ledging plus some cavings cleaned out. No real indications of overpressured shale. Wiper trip as required. Increase mud weight as required to improve with buoyancy and help hole stability.
3/26/1999 0:00	9:00	12:00	3	10255	10255	Continue wiper trip to 8919'. RIH to 10235'.
3/26/1999 0:00	12:00	12:30	0.5	10255	10255	Wash to 10,255'.
3/26/1999 0:00	12:30	14:00	1.5	10255	10255	Circ HiVis sweep.
3/26/1999 0:00	14:00	15:00	1	10255	10255	POH to 9300'.
3/26/1999 0:00	15:00	15:30	0.5	10255	10255	Monitor well. Pump slug.
3/26/1999 0:00	15:30	20:30	5	10255	10255	POH to 3190'.
3/26/1999 0:00	20:30	21:00	0.5	10255	10255	Work through tight spot @ 3190'. Tight spot in Colville Group shales. Likely a function of being open too long. None - not a normal situation for Alpine development drilling.
3/26/1999 0:00	21:00	22:30	1.5	10255	10255	POH. Observed well @ shoe. OK.
3/26/1999 0:00	22:30	0:00	1.5	10255	10255	LD monel BHA. Download MWD.
3/27/1999 0:00	0:00	1:00	1	10255	10255	LD BHA.
3/27/1999 0:00	1:00	8:30	7.5	10255	10255	RU Schlumberger. RIH w/ GR/RES/NEUT/DENS/Dipole Sonic to 7144'. Unable to work tools through bridge. Log out to csg shoe. POH.
3/27/1999 0:00	8:30	12:00	3.5	10255	10255	Run USIT f/ 2780' to surface. RD Schlumberger.
3/27/1999 0:00	12:00	12:30	0.5	10255	10255	Monitor well. Service top drive. Unable to obtain TD logs past bridge at 7144 ft (Lower Kingak). Hole ledging. Wiper trip carried out. Tight hole / ledging below the Alpine Sand. Hole obviously deteriorating with time. Minimize OH time and case off.
3/27/1999 0:00	12:30	13:30	1	10255	10255	MU HO BHA. Wiper trip to condition hole for a second logging attempt. As above
3/27/1999 0:00	13:30	15:00	1.5	10255	10255	RIH to 2740'. As above. As above.
3/27/1999 0:00	15:00	15:30	0.5	10255	10255	Held kick drill. Adjust guide roller spring. As above As above
3/27/1999 0:00	15:30	16:30	1	10255	10255	RIH to 3078'. Tight spot. As above As above
3/27/1999 0:00	16:30	17:00	0.5	10255	10255	Ream f/ 3050' to 3132'. As above As above
3/27/1999 0:00	17:00	22:30	5.5	10255	10255	Blow down top drive. RIH to TD. Reamed tight spots at 7159'-7478'-10236'. As above As above
3/27/1999 0:00	22:30	0:00	1.5	10255	10255	Circ hi vis sweep. As above As above
3/28/1999 0:00	0:00	2:00	2	10255	10255	Spot lo fluid loss pill. Pump slug. Observe well. Blow down. As above As above
3/28/1999 0:00	2:00	4:00	2	10255	10255	POH. Pulled tight at 8974'. Backream to 8900'. Attempt to POH. Hole swabbing. As above As above
3/28/1999 0:00	4:00	5:00	1	10255	10255	RIH to TD. As above As above
3/28/1999 0:00	5:00	10:00	5	10255	10255	Circ and condition mud. Pump 2 hi vis sweeps. Reciprocate pipe without rotating. As above As above

Exhibit 7-7 Construction and Completion Reports
WD-02 Daily Drilling Reports

Date	From	To	Duration	Start Depth	End Depth	Activity
3/28/1999 0:00	10:00	11:30	1.5	10255	10255	Monitor well. Blow down. POH wet to 8811'. No problems. As above As above
3/28/1999 0:00	11:30	19:00	7.5	10255	10255	Pump slug. POH. SLM (no correction). No problems. As above As above
3/28/1999 0:00	19:00	0:00	5	10255	10255	RU Schlumberger. Run GR/RES/NEUT/Density/Dipehole sonic. Unable to work tool below 8796. Log out. Second logging attempt. Hold up in Lower Kingak (Arresting Zone). Ledging as before. Due to deteriorating hole conditions would not normally recommend a second logging attempt. Carried out on WD-2 due to sensitivities associated with a Class 1 disposal well.
3/29/1999 0:00	0:00	1:00	1	10255	10255	POH w/ logging tools. RD Schlumberger. As above As above
3/29/1999 0:00	1:00	1:30	0.5	10255	10255	Service rig and top drive.
3/29/1999 0:00	1:30	3:00	1.5	10255	10255	RIH w/ HO assembly to 2720'.
3/29/1999 0:00	3:00	4:30	1.5	10255	10255	Cut and slip drlg line. Adjust brakes.
3/29/1999 0:00	4:30	8:30	4	10255	10255	RIH to 8730'. Hit bridge.
3/29/1999 0:00	8:30	12:30	4	10255	10255	Wash and ream f/ 8730' to 9127'. Hole sloughing. Conditioning trip prior to running casing. Continuing hole deterioration. Raise MW. Run casing.
3/29/1999 0:00	12:30	13:30	1	10255	10255	RIH to 10210'.
3/29/1999 0:00	13:30	14:30	1	10255	10255	Wash and ream f/ 10210' to 10255'.
3/29/1999 0:00	14:30	17:00	2.5	10255	10255	Circ and condition mud. Pump sweeps.
3/29/1999 0:00	17:00	17:30	0.5	10255	10255	Monitor well 15' off bottom. OK. Unable to work pipe up. Packed off. Work pipe free. Estb'h circ. As above As above
3/29/1999 0:00	17:30	22:30	5	10255	10255	Circ and condition mud. Increase mud wt to 10.4 ppg. Rotate and reciprocate pipe. Pump sweeps As above As above
3/29/1999 0:00	22:30	0:00	1.5	10255	10255	POH
3/30/1999 0:00	0:00	0:30	0.5	10255	10255	POH wet to 7876'. No problems.
3/30/1999 0:00	0:30	1:00	0.5	10255	10255	Blow down top drive. Monitor well. Static.
3/30/1999 0:00	1:00	6:00	5	10255	10255	POH. No problems. Monitor well at the shoe.
3/30/1999 0:00	6:00	7:00	1	10255	10255	LD BHA.
3/30/1999 0:00	7:00	7:30	0.5	10255	10255	Drain stack. Pull wear bushing.
3/30/1999 0:00	7:30	9:30	2	10255	10255	Clear floor. RU Franks fill up tool. RU to run csg.
3/30/1999 0:00	9:30	10:00	0.5	10255	10255	Held prejob safety meeting.
3/30/1999 0:00	10:00	15:30	5.5	10255	10255	RIH w/ 7"" csg to 2750'.
3/30/1999 0:00	15:30	16:00	0.5	10255	10255	CBU.
3/30/1999 0:00	16:00	0:00	8	10255	10255	RIH w/ 7"" csg to 9000'. Break circ every 10 jts. Circ f/ 15 min at 4715' and 6600'. Hole tight at 8900'.
3/31/1999 0:00	0:00	0:30	0.5	10255	10255	CIRC WITH 7"" CSG AT 8,800'.
3/31/1999 0:00	0:30	1:30	1	10255	10255	CHANGE HANDLING TOOLS FOR 7 5/8"" CSG.
3/31/1999 0:00	1:30	3:30	2	10255	10255	RIH WITH 7 5/8"" CSG. SHOE AT 10,230'.
3/31/1999 0:00	3:30	5:30	2	10255	10255	LAY DOWN FILL UP TOOL. MAKE UP LANDING JT AND CEMENTING HEAD. BREAK CIRC.
3/31/1999 0:00	5:30	11:00	5.5	10255	10255	CIRC AND COND MUD AND HOLE FOR CEMENT JOB. RECIPICATE PIPE. ESTABLISH CIRC RATE 8 BPM - 1,050 PSI. FULL RETURNS.NO MUD LOSS.
3/31/1999 0:00	11:00	14:00	3	10255	10255	PJSM - CEMENTING. TEST LINES TO 3,500 PSI. DOWELL CEMENTED 7"" X 7 5/8"" CSG PUMPING 20 BBLS PREFLUSH, 50 BBLS ARCO SPACER @ 12.5 PPG, 1800 SX CL ""G"" (367 BBLS) AT 14.6 - 15.8 PPG.DISPLACED WITH 9.0 PPG BRINE AT 6 - 8 BPM. PLUG BUMPED 37 BBLS EARLY. DID NOT HAVE FULL RETURNS PUMPING LAST 100 BBLS DISPLACEMENT. PLUG DOWN AND JOB COMPLETE @ 1400 HRS. FLOATS HELD. MUD FALLING IN 9 5/8"" ANNULUS.
3/31/1999 0:00	14:00	16:00	2	10255	10255	MONITOR WELL ON TRIP TANK. START N.D. STACK.LOST TOTAL 15 BBLS IN 2 HRS. FINAL LOSS RATE 1.5 BPH.
3/31/1999 0:00	16:00	18:00	2	10255	10255	P.U. BOP'S. LANDED 7 "" X 7 5/8"" CSG WITH 120K ON SLIPS. CUTOFF CSG.

Exhibit 7-7 Construction and Completion Reports

WD-02 Daily Drilling Reports

Date	From	To	Duration	Start Depth	End Depth	Activity
3/31/1999 0:00	18:00	21:30	3.5	10255	10255	L.D. LANDING JT. MOVE BOP'S. MAKE FINAL CUT AND BEVEL 7 5/8"" CSG.
3/31/1999 0:00	21:30	0:00	2.5	10255	10255	INSTALL 7 5/8"" PACK-OFF. N. U. BOP'S. TEST PACK-OFF TO 3500 psi for 15 min.
4/1/1999 0:00	0:00	1:00	1	10255	10255	Finished testing 7 5/8"" pack-off.
4/1/1999 0:00	1:00	4:30	3.5	10255	10255	Pumped 150 bbls fresh water into 9 5/8"" x7 5/8"" annulus at 3 bpm - 750 psi. Freeze protected 7 5/8"" annulus to 2,000' with 45 bbls diesel.Set test plug and changed bottom rams to 3.5"" R.U. to test BOP's.
4/1/1999 0:00	4:30	11:00	6.5	10255	10255	Test BOP's to 250 psi / 4,000 psi - hydril to 2,500 psi. No leaks. Test witness waived by Lou Gramaldi with AOGCC. Volume test koomey.PULLED TEST PLUG AND SET WEAR BUSHING.
4/1/1999 0:00	11:00	11:30	0.5	10255	10255	PAD EVACUATION DRILL - 10 MIN.
4/1/1999 0:00	11:30	12:30	1	10255	10255	ADJUST RISER AND FLOW LINE.
4/1/1999 0:00	12:30	15:30	3	10255	10255	MAKE UP BHA FOR CLEAN OUT RUN.P.U. 6 1/8"" BIT, 7 5/8"" CSG SCRAPER AND RIH P. U. 3.5"" DP TO 1,575'.
4/1/1999 0:00	15:30	16:30	1	10255	10255	PUMP SWEEP AROUND AND CIRC CLEAN.
4/1/1999 0:00	16:30	17:00	0.5	10255	10255	POOH WITH BIT AND SCRAPER.
4/1/1999 0:00	17:00	17:30	0.5	10255	10255	MAKE UP 7"" CSG SCRAPER.
4/1/1999 0:00	17:30	0:00	6.5	10255	10255	RIH PICKING UP 3.5"" D.P. TO 7350'.
4/2/1999 0:00	0:00	3:30	3.5	10255	10255	FINISH RIH PICKING UP 3.5"" DP TO 10,116.
4/2/1999 0:00	3:30	4:00	0.5	10255	10255	WASH FROM 10,116' TO 10,152' PBTD.
4/2/1999 0:00	4:00	5:30	1.5	10255	10255	CIRC.
4/2/1999 0:00	5:30	6:30	1	10255	10255	TEST 7 5/8"" X 7"" CSG TO 3,500 PSI FOR 30 MIN. LOST 50 PSI IN30 MIN.
4/2/1999 0:00	6:30	9:00	2.5	10255	10255	DISPLACE WELL WITH CLEAN 9.0PPG SEA WATER - PUMPE 30 BBLS CAUSTIC WASH, 100 BBLS FRESH WATER, 315 BBLS 9.0 PPG BRINE.
4/2/1999 0:00	9:00	15:30	6.5	10255	10255	POOH LAYING DOWN 3.5"" TUBING AND BHA.
4/2/1999 0:00	15:30	16:00	0.5	10255	10255	SERVICE RIG AND CHANGE HANDLING TOOLS TO 5"".
4/2/1999 0:00	16:00	18:30	2.5	10255	10255	LD 6 3/4"" DC'S AND 5"" DP OUT OF DERRICK.
4/2/1999 0:00	18:30	0:00	5.5	10255	10255	PJSM WITH SCHLUMBERGER. R.U. SCHLUMBERGER - TEST LUBRICATOR TO 500 PSI. RAN USIT LOG FROM 10125' to 4660'. Good cement across zones of interest. TOp of cement @ 6000'. USIT log witnessed by Chuck Scheve with AOGCC.
4/3/1999 0:00	0:00	1:30	1.5	10255	10255	FINISHED RUNNING USIT LOG. POOH WITH W.L. TOOLS. R.D. SCHLUMBERGER. CLEAR FLOOR.
4/3/1999 0:00	1:30	12:00	10.5	10255	10255	PJSM. RU TO RUN 4.5"" TUBING.RIH PICKING UP TAIL PIPE ASSEMBLY, 7"" BAKER SABL-3 PACKER, AND 214 JTS 12.6# L80 IBTM TUBING.
4/3/1999 0:00	12:00	15:00	3	10255	10255	MAKE UP LANDING JT FOR HANGER. R.U. TO RUN 4.5"" STL-FL TUBING AND DHH SYSTEM. PJSM. NOTE: BOB NOVICH STRAINED RIGHT ANKLE WALKING DOWN STAIRS AT DOYON CAMP - FIRST AID.
4/3/1999 0:00	15:00	0:00	9	10255	10255	RAN 29 JTS 4.5"" STL-FL TUBING - TORQUE TURN. STRAP ON DHH. MEGGER EVERY 10 JTS.
4/4/1999 0:00	0:00	2:00	2	10255	10255	FINISHED RUNNING TOTAL 39 JTS 4.5"" STLFJ TUBING & DHH WIRE.
4/4/1999 0:00	2:00	5:30	3.5	10255	10255	SPACE OUT TBG FOR PENETRATOR/ TBG HEAD/ PIG TAIL MAKE UP. NOTE: PENETRATOR / TBG HANGER WILL NOT LAND IN TBG HEAD WITHOUT DAMAGE.

Exhibit 7-7 Construction and Completion Reports
WD-02 Daily Drilling Reports

Date	From	To	Duration	Start Depth	End Depth	Activity
4/4/1999 0:00	5:30	7:30	2	10255	10255	PREPARE TO TEST TUBING - L.D. LANDING JT - TORQUE TBG HANGER. DISCONNECT AND REMOVE PENETRATOR. Combination of BIW penetrator and pig tail from heat trace cable too long to fit in the void between the tubing hanger and the top of the 7 5/8 in. casing hanger pack off. Stack up test had failed to identify this problem since pig tail was not available / used. Also pig-tail was longer and had bigger OD than normal. Action : hang of tubing and install a tubing head in top of the wellhead to allow penetrator / pig tail to fit in under the hanger. Solution : insist that all equipment is included in the stack up trial and have ARCO personnel there to witness.
4/4/1999 0:00	7:30	10:30	3	10255	10255	RU OTIS SLICK LINE UNIT. SET PLUG IN ""DB"" PROFILE @ 1,326'. Additional test of the tubing required due to concerns about make up torque readings while making up the 4-1/2 in. STL tubing. Correct action for this situation. STL is not a commonly used connection and it was correct to verify the integrity of the tubing.
4/4/1999 0:00	10:30	11:00	0.5	10255	10255	PRESSURE TEST 4.5"" STLFJ TUBING TO 3,500 PSI FOR 30 MIN. As above As above
4/4/1999 0:00	11:00	12:30	1.5	10255	10255	OTIS RETRIEVE BLANKING PLUG @ 1,326'. As above As above
4/4/1999 0:00	12:30	16:00	3.5	10255	10255	PREPARE TO SET STORM PACKER TO NIPPLE DOWN BOP'S FOR WELL HEAD WORK. LD TBG HANGER AND MAKE UP XO'S. LOWER FL IN WELL TO 50 BELOW G.L. W/ AIR. W.O. STORM PACKER. SECURE PIG TAIL TO TBG. DECIDED NOT TO RUN PIG TAIL INTO 7 5/8"" CSG - HIGH RISK FOR DAMAGE. Continuation of problem with the BIW connector and pig tail for the heat trace. As above
4/4/1999 0:00	16:00	0:00	8	10255	10255	PU STACK. LAND 4.5"" TUBING ON SLIP TYPE ELEVATORS. STRIP 11"" 5M TBG SPOOL OVER TUBING.N.U. TUBING HEAD AND BOP'S. As above As above
4/5/1999 0:00	0:00	2:30	2.5	10255	10255	LD DRILL PIPE. MAKE UP TBG HANGER AND PENETRATOR. MEGGER LINE. UNABLE TO CONNECT DHH LINE - TO SHORT AFTER MOVING TUBING. As above As above
4/5/1999 0:00	2:30	6:00	3.5	10255	10255	SPACE OUT TUBING TO FIT DHH LINE. TEST LINE/ PENETRATOR. LAND TBG HANGER AND RILDS. As above As above
4/5/1999 0:00	6:00	12:00	6	10255	10255	R.U. TO REV CIRC. DISPLACE WELL TO CLEAN TREATED 9.0 PPG BRINE (74 NTU'S). PUMPED 65 DIESEL FREEZE PROTECTION.
4/5/1999 0:00	12:00	12:30	0.5	10255	10255	U-TUBE DIESEL. FREEZE PROTECTED TO 2,800'.
4/5/1999 0:00	12:30	15:00	2.5	10255	10255	PRESSURE WELL TO 1,000 PSI TO TEST TBG HEAD FLANGES - OK. R.O.L.D.S. SPOT TBG HANGER 18"" ABOVE TBG HEAD. DROPPED BALL. SET PACKER @ 7,864' WITH 3,500 PSI AND HELD 30 MIN FOR TBG TEST. WLEG @ 7,975'. LOST 95 PSI IN 30 MIN.SHEARED OUT BALL @ 3850 PSI. PULLED 20K OVER ON PACKER. LANDED TBG WITH 55K ON HANGER - 20K ON PACKER. RILDS.
4/5/1999 0:00	15:00	17:00	2	10255	10255	TEST CSG / PACKER - PRESSURE TBG TO 875 PSI - CSG TO 3,500 PSI. HELD 30 MIN - FINAL CSG PRESSURE 3,490 PSI, FINAL TBG PRESSURE 875 PSI. LD LANDING JT.
4/5/1999 0:00	17:00	21:00	4	10255	10255	SET TWCV. ND BOP'S. NU ADAPTOR FLANGE AND 4 1/16' 5M TREE. TEST TBG HANGER AND TBG HEAD TO 5,000 PSI. TEST TREE TO 5,000 PSI.TEST HEAT TRACE WIRE. CLEAN OUT CELLAR AND INSTALL GAGES. R.R. @ 21OO HRS 4-5-99.
4/5/1999 0:00	21:00	0:00	3	10255	10255	RD FLOOR. PREP FLOOR FOR JACKING. MOVE PIT AND MOTOR COMPLEXES.
4/6/1999 0:00	7:30	10:30	3	10255	10255	Clean pad, scaffold wellhead, MIRU HES & safety meeting.
4/6/1999 0:00	3:00	6:00	3	10255	10255	Drift Tbg w/ 3.80"" to XN @ 7901' WLM, Tag PBTD w/ 30' x 3 3/8"" Dummy Gun @ 10101' WLM, RDMO HES.
4/6/1999 0:00	6:00	12:30	6.5	10255	10255	MIRU SWS, safety meeting, run gyro survey from surf to PBTD, secure well.
4/7/1999 0:00	6:30	8:49	2.33	10255	10255	RU, tst lub, RIH to perforate, Tag PBTD @ 10,153' ELM
4/7/1999 0:00	2:19	11:44	9.42	10255	10255	Perf from 10017'-10047', 9900'-9020', 9876'-9896', 9837'-9867' GRM per USIT 04/06/99 log w/ 3 3/8"" HSC 34B chrgs 6 spf 60 deg phase.
4/7/1999 0:00	11:44	13:29	1.75	10255	10255	Secure well

Exhibit 7-7 Construction and Completion Reports

WD-02 Daily Drilling Reports

Date	From	To	Duration	Start Depth	End Depth	Activity
4/8/1999 0:00	6:30	9:34	3.08	10255	10255	RU, tst lubricator, RIH to perf.
4/8/1999 0:00	3:04	11:29	8.42	10255	10255	Perf from 9803'-9818', 9702'-9712', 9612'-9627', 9532'-9552' GRM per USIT log 04/06/99 w/ 3 3/8"" HSC 34B chrgs 6 spf 60 deg phase.
4/8/1999 0:00	11:29	13:29	2	10255	10255	Secure well.
4/9/1999 0:00	6:30	9:40	3.17	10255	10255	RU, tst lubricator, RIH to perf.
4/9/1999 0:00	3:10	5:55	2.75	10255	10255	Perf from 9514'-9532', 9459'-9472' GRM per USIT log 04/06/99 w/ 3 3/8"" HSC 34B chrgs 6 spf 60 deg phase.
4/9/1999 0:00	5:55	8:29	2.58	10255	10255	Secure well.
4/10/1999 0:00	6:00	18:00	12	10255	10255	Waiting on frac fleet to perform breakdown injectivity test and pump in for RA tracer survey. Load frac tanks and roll with hot oil trucks.
4/11/1999 0:00	5:00	7:00	2	10255	10255	MIRU Schlumberger. Test tools & lubricator.
4/11/1999 0:00	2:00	5:30	3.5	10255	10255	GIH with PLTS/RA ejector/GR/CCL. Run base logs. RU Dowell.
4/11/1999 0:00	5:30	7:00	1.5	10255	10255	Load hole with 8.5 ppg slickwater. Mini-step test to break down.
4/11/1999 0:00	7:00	8:45	1.75	10255	10255	Step Rate Test - Initial rate 1/4 bpm @ 846 psi WHP. Final rate 3 BPM @ 2250 psi WHP. ISIP 2048 psi, FG 0.667.
4/11/1999 0:00	8:45	9:00	0.25	10255	10255	Flush slickwater with SW and F-75 surfactant. Final rates 15 BPM at 3150 psi.
4/11/1999 0:00	9:00	11:30	2.5	10255	10255	Run RA tracer logs across perfs. No channels up or down. No leaks from the packer down. All fluid exiting perforations.
4/11/1999 0:00	11:30	12:30	1	10255	10255	Spinner survey perfs at 3/4 BPM and 3 BPM.
4/11/1999 0:00	12:30	14:00	1.5	10255	10255	Dump tracer. POOH with Schlumberger. Pump 2 BPM to wash tools.
4/11/1999 0:00	14:00	15:00	1	10255	10255	Test IA to 3500 psi. 30 min pressure 3327 psi. Passed test.
4/11/1999 0:00	15:00	17:30	2.5	10255	10255	Empty tanks and lines of fluid down well. Pump 10 BPM at 3000 psi.
4/11/1999 0:00	17:30	18:45	1.25	10255	10255	RD Dowell and hot oil. Secure well.
4/12/1999 0:00	9:00	11:00	2	10255	10255	RU HES. Perform MITIA to 3500 psia. Lost 50 psi in 30 minutes. RU and test lubricator.
4/12/1999 0:00	2:00	5:00	3	10255	10255	Drift tbg to SSSV. POOH. Run Camco A1 Inj valve with 15/32"" orifice plate. Set in SSSV. PT. POOH. RD. Well secured for tie-in.

Exhibit 7-7 Construction and Completion Reports
WD-02 Rig Workover

Date	From	To	Duration	Start Depth	End Depth	Activity
4/30/2011 0:00	12:00	0:00	12	0	0	Move Rig t/ CD1 (WD-02)
5/1/2011 0:00	0:00	12:00	12	0	0	Continue to Move Rig, Pipe Shed, Pits and Motors to CD1 (WD-02)
5/1/2011 0:00	12:00	22:00	10	0	0	Continue to Move Rig, Pipe Shed, Pits and Motors to CD1 (WD-02) - Spot Pits, Motors, Sub Base and Pipe Shed - Connect All Service Lines - Take On Water and Connect High-Line Power - Accept Rig @ 2200
5/1/2011 0:00	22:00	0:00	2	0	0	R/U Hard Line f/ IA to Tiger Tank - R/U Hard Lines t/ Displace Well t/ 9.8 PPG Bine Troubleshoot High Line / Rig Power Problem; No SCR's
5/2/2011 0:00	0:00	0:45	0.75	0	0	Continue to R/U Hardlines to Displace Well - R/U Squeeze Manifold
5/2/2011 0:00	0:45	1:45	1	0	0	PJSM, Then Pull BPV w/ FMC Lubricator ~ 50 Psi on Tubing, 0 Psi on IA
5/2/2011 0:00	1:45	3:00	1.25	0	0	Take On Remaining Brine Needed to Complete Displacement - R/U Hard Lines t/ Tree Cap - SIMOPS: Load Pipe Shed w/ 4" DP
5/2/2011 0:00	3:00	5:00	2	0	0	Displace Well Bore Fluids (Diesel/Brine) t/ 9.8 PPG Brine - Pumped 365 Bbls @ 4 BPM w/ 285 Bbls Returned to the Tiger Tank (80 Bbl Loss)
5/2/2011 0:00	5:00	5:45	0.75	0	0	Monitor Well - Initially Flowing w/ Noticeable Decreasing Rate After Shut Down - Well Static in 15 Minutes - Monitor Well for Additional 30 Minutes; Remained Static
5/2/2011 0:00	5:45	6:00	0.25	0	0	Blow Down Hard Line to Tiger Tank - R/U to Pump Down Back Side
5/2/2011 0:00	6:00	6:15	0.25	0	0	Install BPV
5/2/2011 0:00	6:15	7:00	0.75	0	0	Test BPV in Direction of Flow t/ 1,000 Psi f/ 10 Minutes by Pumping Down IA @ 5.6 BPM - Bull Headed 60 Bbls Into Formation
5/2/2011 0:00	7:00	8:15	1.25	0	0	OWFF (Flowing) - Well Static After 30 Minutes - Beld Back 24 Bbls - Monitored Well for Additional 30 Minutes After Static
5/2/2011 0:00	8:15	8:30	0.25	0	0	Blow Down & R/D Hard Lines
5/2/2011 0:00	8:30	16:30	8	0	0	PJSM - Nipple Down Tree - Install Blanking Plug - Dress Tubing Hanger Threads - Remove Alpine Quick Connect Adapter on Bottom of BOPE Stack - M/U 4' Spacer Spool - N/U BOPE - Cut Riser to Length - N/U Riser and Lines
5/2/2011 0:00	16:30	17:00	0.5	0	0	Fill Stack and Lines w/ Water - Prep for BOPE Test
5/2/2011 0:00	17:00	22:00	5	0	0	Test BOPE w/ 4 ½" Test Joint; Test Upper and Lower Rams, Blind Rams, Choke Manifold Valves 1-16, 4" DEMCO, TIW, Dart, Auto/Manual IBOP, HCR/Manual Choke & Kill Valves/Lines t/ 250/3500 Psi - Test Annular w/ 4 ½" Test Joint t/ 250/2500 Psi - Perform Accumulator Draw Down Test
5/2/2011 0:00	22:00	22:45	0.75	0	0	R/D Test Equipment - Pull Blanking Plug and BPV
5/2/2011 0:00	22:45	23:15	0.5	0	0	M/U Fishing BHA as Follows: BOT Bull nose, Pack Off, Spear, XO, 5' DP Pup, 1 Jt 4" DP
5/2/2011 0:00	23:15	0:00	0.75	0	0	Spear Tubing Hanger and Pull to the Rig Floor - Pulled Free @ 150K (Indicated)
5/3/2011 0:00	0:00	1:00	1	7840	7840	PJSM. LD spear. RU tubing equipment.. LD tubing hanger.
5/3/2011 0:00	1:00	12:00	11	7840	2880	POH laying down 4.5" 12.6# L-80 STL tubing from 7840' to 2880'. Removed 603 bands and 200 flat guards from tubing.
5/3/2011 0:00	12:00	14:30	2.5	2880	1850	Continue POH with tubing from 2880' to 1850'.
5/3/2011 0:00	14:30	15:00	0.5	1850	1850	LD Camco spooling unit from floor along with tubing hanger and DB nipple.
5/3/2011 0:00	15:00	15:30	0.5	1850	1850	Service rig.
5/3/2011 0:00	15:30	16:00	0.5	1850	1850	Repair foot throttle control.
5/3/2011 0:00	16:00	19:15	3.25	1850	0	Continue POH with tubing from 1850'. LD cut jt. Recovered cut jt at 19.1', 247 jts tubing, DB nipple assembly, space out pups and tubing hanger.
5/3/2011 0:00	19:15	20:15	1	0	0	MU pup jt on to top of landing jt. RD tubing tongs and other running tools. Break and LD spear assembly.
5/3/2011 0:00	20:15	21:45	1.5	0	0	RU and test lower and upper pipe rams to 250/3500 psi with 4" test jt. Test annular to 250/2500 psi. RD test equipment and install wear ring.
5/3/2011 0:00	21:45	0:00	2.25	0	313	PU components for BHA #2: Dressoff shoe. XO Bushing Overshot + ext'n. Top sub Bumper jar Oil jar 7 x 4 3/4" DC's Jar intensifier Pump out sub XO 2 x HWDP.
5/4/2011 0:00	0:00	1:30	1.5	7840	7840	PJSM. Slip & cut 120' drilling line. Service top drive. Set block height.
5/4/2011 0:00	1:30	9:15	7.75	7835	7835	MU 3 jts 4" DP and stand back in derrick. RIH with BHA #2 from 313' to 7789' while singling in 4" DP from pipeshed to release and retrieve K anchor.
5/4/2011 0:00	9:15	9:45	0.5	7844	7844	Wash down to TOF at 7844' DP measurement - 2 bpm @ 130 psi.

Exhibit 7-7 Construction and Completion Reports
WD-02 Rig Workover

Date	From	To	Duration	Start Depth	End Depth	Activity
5/4/2011 0:00	9:45	11:00	1.25	7844	7865	Engage tubing stub with overshot and rotate right to release K anchor.
5/4/2011 0:00	11:00	12:00	1	7865	7865	Flow check well. Blow down top drive. POH with fish to 7760'.
5/4/2011 0:00	12:00	13:15	1.25	7865	7865	Mix & pump dry job. Monitor well - static. Blow down top drive.
5/4/2011 0:00	13:15	18:45	5.5	7865	7865	POH with fish from 7844'. Recover 12' of 4.5" tubing below cut, 4.5" pup jt and top connection on K anchor. Acme thread on top of K anchor twisted off leaving anchor still engaged in packer. Make service breaks on overshot. LD tools and fish.
5/4/2011 0:00	18:45	20:30	1.75	7865	7865	Clear floor. PU tools for next run (#3) - milling packer: 6" Packer mill. 3 x Boot baskets. XO Sub. Bumper sub. Oil jar. 7 x 4 3/4" DC's. Pump out sub. XO Sub. 2 x 4" HWDP.
5/4/2011 0:00	20:30	22:30	2	7865	7865	RIH. PU 78 singles from pipe shed to 2786'.
5/4/2011 0:00	22:30	0:00	1.5	7865	7865	RIH with stands to 6507'.
5/5/2011 0:00	0:00	0:30	0.5	7862	7862	RIH from 6507' and tag up on top of packer at 7862'.
5/5/2011 0:00	0:30	9:45	9.25	7862	7862	Start milling packer at 7862' - 6 bpm @ 900 psi. 60 rpm with ~8 klbs WOB. Made 6-8" progress in first hour. No further progress. Try varying WOB, RPM, flowrate combinations. Dry drill w/o pump. PU and tag up hard on packer several times. Continue milling as above, seeing only minor torque fluctuations.
5/5/2011 0:00	9:45	13:45	4	7862	7862	Pump dry job. Monitor well until static. Blow down top drive. POH to 312'.
5/5/2011 0:00	13:45	15:00	1.25	7862	7862	Stand back DC's. Empty boot baskets. Recovered small metal ring stuck on mill - part of anchor. Boot baskets had ~2 cups of small metal debris. LD BHA components.
5/5/2011 0:00	15:00	18:45	3.75	7862	7862	MU short catch spear assembly - BHA #4. RIH to 7862'.
5/5/2011 0:00	18:45	19:45	1	7862	7862	Engage TOF with spear at 7862'. PU to 275 klbs. (~55 klbs over string wt). Anchor may still be engaged in packer. Jar up multiple times at 275 klbs attempting to jar anchor out of packer body - no success. Consider that anchor may have been milled up and spear grapple is now engaged in packer body. Release spear from top of packer.
5/5/2011 0:00	19:45	23:15	3.5	7862	7862	Monitor well - slight drop in fluid level. Blow down top drive. POH with spear assembly to 297'.
5/5/2011 0:00	23:15	0:00	0.75	7862	7862	Stand back DC's. LD BHA components. Grapple from spear was left in hole apparently when releasing spear from packer.
5/6/2011 0:00	0:00	1:00	1	7862	7862	MU milling BHA #5.
5/6/2011 0:00	1:00	4:30	3.5	7862	7862	RIH with BHA #5 from 310' to 7862'.
5/6/2011 0:00	4:30	5:00	0.5	7862	7863	Tagged up on packer ~1' high. Set down 15 klbs and weight dropped off. Appear to have pushed grapple down inside packer. Tag up with mill and commence milling on packer. Milled approx 1' of packer body in 30 minutes - packer started moving down hole. Push packer down to 7941' MD.
5/6/2011 0:00	5:00	7:15	2.25	7863	7863	CBU & pump sweep at 6 bpm @ 840 psi. Blow down top drive. Flow check well - static after 28 min.
5/6/2011 0:00	7:15	9:00	1.75	7863	9878	RIH looking for packer. Set down 20 klbs at 9878'.
5/6/2011 0:00	9:00	9:30	0.5	9878	9878	Circ 3 bpm @ 230 psi and 30 rpm to clean off top of packer prior to fishing. Flow check well.
5/6/2011 0:00	9:30	10:00	0.5	9878	9878	Pump dry job. Flow check. Static after 7 min - 7 bbl gain. Monitor for 10 min after static - OK.
5/6/2011 0:00	10:00	14:45	4.75	9878	9878	Blow down top drive. Flow check well. POH to 312'.
5/6/2011 0:00	14:45	15:15	0.5	9878	9878	Rack back HWDP & DC's. LD milling BHA components.
5/6/2011 0:00	15:15	16:15	1	9878	9878	Clear floor. MU spear BHA #6 to fish packer assembly.
5/6/2011 0:00	16:15	20:45	4.5	9878	9878	RIH with BHA #6 to 9857'.
5/6/2011 0:00	20:45	22:30	1.75	9878	9878	Attempt to break circ above fish. No success - string appears to be plugged. RU & reverse circ up to 2.5 bpm @ 270 psi - OK. Reverse circ 60 bbls w/o problem.
5/6/2011 0:00	22:30	23:15	0.75	9878	9878	RU to circ normally. Circ down to top of packer 2.5 bpm @ 300 psi. Spear in to TOF at 9878' and set down 30 klbs. PU & repeat 3 additional times.
5/6/2011 0:00	23:15	0:00	0.75	9878	9878	Pull & rack back 1 stand. Fluid columns out of balance and flowing over top of DP. Pump dry job and monitor well.
5/7/2011 0:00	0:00	0:45	0.75	9878	9878	Flow check well - static. POH from 9762' to 9667'
5/7/2011 0:00	0:45	1:15	0.5	9878	9878	Service rig & top drive.
5/7/2011 0:00	1:15	1:30	0.25	9878	9878	Work on draw works foot throttle control.
5/7/2011 0:00	1:30	6:45	5.25	9878	9878	POH from 9667' to 315'.

Date	From	To	Duration	Start Depth	End Depth	Activity
5/7/2011 0:00	6:45	8:30	1.75	9878	9878	Flow check - OK. Clean magnets. LD magnets & jars. Rack back HWDP & DC's. LD fishing tools - did not recover fish. Nose of spear had marks & gouges indicating it had hit junk/debris on top of packer. Grapple was still in the catch position and had not entered top of fish.
5/7/2011 0:00	8:30	12:00	3.5	9878	9878	Wait on additional fishing tools from Deadhorse. Perform rig maintenance while waiting.
5/7/2011 0:00	12:00	14:00	2	9878	9878	MU BHA #7 with Reverse Circ Junk Basket.
5/7/2011 0:00	14:00	20:30	6.5	9878	9878	RIH with BHA #7 to 9875'.
5/7/2011 0:00	20:30	22:00	1.5	9878	9878	Tag top of fish at 9875'. Circ at 8.5 bpm @ 2500 psi. Free torque above fish 8500 ft lbs. Work and rotate RCJB at 60 rpm up and down on top of packer to remove debris. Seeing torque spikes when rotating up to 14000 ft lbs as if rotating on junk. Flow check well until static - OK.
5/7/2011 0:00	22:00	0:00	2	9878	9878	Replace rheostat in draw works throttle. PJSM. Slip & cut drilling line.
5/8/2011 0:00	0:00	0:15	0.25	9878	9878	Pump dry job. Blow down top drive. Monitor well
5/8/2011 0:00	0:15	4:30	4.25	9878	9878	POH with rev circ junk basket.
5/8/2011 0:00	4:30	6:00	1.5	9878	9878	Flow check - OK. Clean & LD magnet & jars. Rack back HWDP & DC's. Clean out RCJB. Recovered 2 ea thin metal strips approx 6" long and 2 small pcs packer. Boot baskets had misc milling metal debris.
5/8/2011 0:00	6:00	7:30	1.5	9878	9878	Clear floor. MU BHA #8 with 3 5/8" junk mill and 3.85" stabilizer on 3" OD extension 10' long.
5/8/2011 0:00	7:30	12:30	5	9878	9878	RIH with BHA #8 to top of fish at 9876'.
5/8/2011 0:00	12:30	14:00	1.5	9878	9878	Get PUW = 250. SOW = 200. ROT = 225. Start milling at 40-70 rpm with 8-11 k ftlbs torque and 2-10 klbs WOB. Mill from 9876 down to 9891' until clean.
5/8/2011 0:00	14:00	14:45	0.75	9878	9878	Pump dry job. Monitor well. Got back 9 bbls & stabilized in ~20 min.
5/8/2011 0:00	14:45	20:30	5.75	9878	9878	POH with milling assembly. LD BHA components and clear floor.
5/8/2011 0:00	20:30	22:00	1.5	9878	9878	Pull wear bushing. Set junk catcher wear bushing. Flush BOP stack w/ hi vis pill. Pull junk catcher wear bushing.
5/8/2011 0:00	22:00	0:00	2	9878	9878	Set BOP test plug & RU test equipment. Test annular preventer to 250/3500 psi for 5 min each test
5/9/2011 0:00	0:00	5:45	5.75	9878	9878	Continue BOP test. Test upper & lower VBR's with 4" test jt. Test choke manifold valves, manual & hyd K & C line valves. Test manual and auto IBOP and floor valves. Auto IBOP failed test. Test blind rams and perform accumulator draw down test. Test upper and lower VBR's with 3.5" test jt. All tests to 250/3500 psi for 5 min each test. Witness of test waived by AOGCC Rep Lou Grimaldi.
5/9/2011 0:00	5:45	6:15	0.5	9878	9878	RD test equipment and blow down lines. Pull test plug and set wear ring.
5/9/2011 0:00	6:15	8:30	2.25	9878	9878	PJSM. Remove & replace auto IBOP on top drive.
5/9/2011 0:00	8:30	9:00	0.5	9878	9878	Test IBOP to 250/3500 psi for 5 min - passed.
5/9/2011 0:00	9:00	10:15	1.25	9878	9878	Re-install hoses, clamps, bell guide and actuator covers. Clear & clean floor.
5/9/2011 0:00	10:15	11:15	1	9878	9878	PJSM. Change elevators. MU fishing BHA #9 with spear to retrieve packer/tailpipe assembly.
5/9/2011 0:00	11:15	17:00	5.75	9878	9878	RIH with BHA #9 to 9876'.
5/9/2011 0:00	17:00	17:30	0.5	9878	9876	PUW = 250 klbs SOW = 200 klbs. Engage fish with spear and set down 25 klbs. Break circ at 3 bpm @ 650 psi and work fish free at 300 klbs.
5/9/2011 0:00	17:30	18:00	0.5	9876	9876	Pump out from 9876' to 9786'. PU 2 singles and work tight pipe up to 350 klbs. Work free - possible junk alongside fish when pulling up. Pump dry job.
5/9/2011 0:00	18:00	18:15	0.25	9876	9876	PJSM. Flow check well. Static in 11 minutes. Got back 6.5 bbls brine. Blow down top drive.
5/9/2011 0:00	18:15	0:00	5.75	9876	9876	POH with fish. Hung up twice more and had to jar free up to 325 klbs - then OK.
5/10/2011 0:00	0:00	1:00	1	2691	312	Continue POOH f/ 2691' to 312'
5/10/2011 0:00	1:00	1:45	0.75	312	248	Flow ckeck - Stand back HWDP - Change out elevators & stand back drill collars
5/10/2011 0:00	1:45	2:45	1	248	0	Lay down BHA # 9 (spear assembly) lay down fish (packer & tail pipe)
5/10/2011 0:00	2:45	3:00	0.25	0	0	PJSM on making up BHA # 10

Exhibit 7-7 Construction and Completion Reports
WD-02 Rig Workover

Date	From	To	Duration	Start Depth	End Depth	Activity
5/10/2011 0:00	3:00	3:30	0.5	0	327	MU BHA # 10 -(mill - casing scraper - 3 boot baskets - jars - bumper sub - DC's - string magnet - pump out sub - HWDP
5/10/2011 0:00	3:30	7:00	3.5	327	9388	RIH w/ BHA # 10 f/ 327' to 9388'
5/10/2011 0:00	7:00	9:15	2.25	9388	9388	Pumped hi-vis sweep @ 8 bbls/min @ 1380 psi - Flow ck well static in 48 mins - gained 19 bbls
5/10/2011 0:00	9:15	9:45	0.5	9388	9388	Pumped dry job - blow down TD - Flow ck. well static in 11 mins.
5/10/2011 0:00	9:45	14:30	4.75	9388	327	POOH w/ BHA # 10 f/ 9388' to 327'
5/10/2011 0:00	14:30	16:30	2	327	0	LD BHA components and clear floor.
5/10/2011 0:00	16:30	22:00	5.5	0	0	PJSM. RU Halliburton E line to run PDS 40 arm caliper. RIH to 9430' and log out to surface. Noted a potentially severe corrosion pit at 7836' - just above original packer setting depth of 7865'. RD E-line.
5/10/2011 0:00	22:00	0:00	2	0	750	MU Baker test packer on 4 3/4" DC's and 4" DP. RIH with packer to pressure test 7" & 7 5/8" casing.
5/11/2011 0:00	0:00	5:30	5.5	750	9375	Continue RIH with Baker Retrieve-a-Matic test packer to 9375'.
5/11/2011 0:00	5:30	7:15	1.75	9375	9375	Set packer at 9375' and close upper pipe rams. RU to test casing. Replace pressure gauge that was reading incorrectly. Test 7" and 7 5/8" casing to 3650 psi for 30 min. Pressure dropped 50 psi in first 9 minutes then stabilized at 3600 psi for remaining 21 minutes. Pressure test was witnessed by EPA Rep Talib Syed.
5/11/2011 0:00	7:15	13:15	6	9375	372	Unseat packer and flow check well - OK. Rack back 1 stand. Pump dry job. Blow down top drive. Monitor well. POH to 372'.
5/11/2011 0:00	13:15	15:00	1.75	372	372	Monitor well - static. Slip & cut drilling line.
5/11/2011 0:00	15:00	16:00	1	372	0	LD BHA components & test packer.
5/11/2011 0:00	16:00	0:00	8	0	5000	PJSM. RU tubing running equipment. Run 3.5" 9.3# L-80 EUE-M tubing completion: WLEG XN Nipple Baker FHL Packer with PBR/Seal Ass'y Camco KBMG GLM w/shear valve Camco DS Nipple 160 jts in at MN.
5/12/2011 0:00	0:00	4:45	4.75	5000	9341	Continue running 3.5" tubing f/ 4578' to 9341' - PU wt. 150 SO wt 140 Run total of 301 jts 9.3# L-80 EUE-M tubing.
5/12/2011 0:00	4:45	5:15	0.5	9341	9376	MU 8' pup, XO, 1 jt 4" DP to space out tubing string to place top of packer at 9320.97' & tbg tail @ 9376.44'
5/12/2011 0:00	5:15	5:45	0.5	9376	9376	Held PJSM w/crew on displacing well to inhibited brine
5/12/2011 0:00	5:45	7:30	1.75	9376	9376	Displaced well to 9.7 ppg inhibited brine (237 bbls) followed by 75 bbls - 9.7 ppg brine @ 3 bbls/min @ 260 psi
5/12/2011 0:00	7:30	7:45	0.25	9376	9376	Monitor well - static
5/12/2011 0:00	7:45	8:00	0.25	9376	9376	Break out head pin & drop rod/ball assembly for packer setting (EPA Rep. witnessed) MU head pin - Pressure up on tbg to 2000 pis (held for 5 mins.) - slacked off 25 k (packer set) - pressure up to 2500 psi
5/12/2011 0:00	8:00	8:30	0.5	9376	9376	Bleed off tbg pressure - Pressure test tbg x 7" casing annulus to 1000 psi for 10 mins. OK
5/12/2011 0:00	8:30	8:45	0.25	9376	9376	Bleed off pressure from annulus - Pressure up on tbg to 1000 psi - Pulled up to 175 k to shear off PBR - Set back down and obtain space out measurements - RD lines & head pin - Blow down lines
5/12/2011 0:00	8:45	9:00	0.25	9376	9376	LD 4" jt of DP - XO - 8' tbg pup jt & 1 jt 3 1/2" tbg
5/12/2011 0:00	9:00	9:45	0.75	9376	9376	Chnage elevators - MU tbg wear bushing pulling tool - MU landing jt B - Pull wear bushing - LD pulling tool & landing jt. B
5/12/2011 0:00	9:45	11:00	1.25	9376	9376	PU 1 jt 3 1/2" tbg - MU 2' space out pup - PU tbg hanger & landing jt. - RIH & land tbg hanger in wellhead w/ tbg tail @ 9376.44' - XN nipple @ 9364.08' - Packer @ 9320.97' - GLM @ 9249.21' - DB nipple @ 2095.44'
5/12/2011 0:00	11:00	13:00	2	9376	9376	Torque up landing jt into tbg hanger - LD mouse hole - RU lines to tbg & annulus -

Exhibit 7-7 Construction and Completion Reports
WD-02 Rig Workover

Date	From	To	Duration	Start Depth	End Depth	Activity
5/12/2011 0:00	13:00	14:45	1.75	9376	9376	Pressure test lines to 3700 psi - Test annulus to 1000 psi to confirm seals into PBR - Test tbg to 3500 psi for 30 mins. - bleed down tbg to 2200 psi - pressure up on annulus to 3500 psi & test IA for 30 mins. (pressure test witnessed by EPA Rep. Talib Syed) - bleed down annulus to 0 psi - Bleed down tbg to 0 psi - pressure back up on annulus to 2750 psi to shear out DCK valve in GLM
5/12/2011 0:00	14:45	15:45	1	9376	9376	LD landing jt. Set TWC. MU landing jt. Test TWC from below thru shear valve to 2600 psi for 10 min - OK.
5/12/2011 0:00	15:45	16:30	0.75	9376	9376	LD landing jt & hard line. Clear rig floor.
5/12/2011 0:00	16:30	20:30	4	9376	9376	PJSM. ND BOPE. Remove spacer spool from stack and install Alpine head Stand back BOP on stump.
5/12/2011 0:00	20:30	0:00	3.5	9376	9376	PJSM. NU tubing head adaptor and tree.
5/13/2011 0:00	0:00	0:45	0.75	9376	9376	Pressure test tubing head adaptor and tree to 5000 psi. Good test - no visible leaks noted.
5/13/2011 0:00	0:45	1:15	0.5	9376	9376	Pull TWC.
5/13/2011 0:00	1:15	2:00	0.75	9376	9376	PJSM. RU hard line to Xmas tree and IA. Hook up floor manifold.
5/13/2011 0:00	2:00	4:00	2	9376	9376	PJSM. Hook up Little Red. Flood lines and test to 2500 psi. Pump 65 bbls diesel to IA - 2.5 bpm @ 1600 psi final pressure. Line up manifold & U-tube diesel into tbg.
5/13/2011 0:00	4:00	5:45	1.75	9376	9376	Vac out lines & manifold - RD lines & manifold.
5/13/2011 0:00	5:45	6:15	0.5	9376	9376	Set BPV & Secure well.
5/13/2011 0:00	6:15	8:15	2	9376	9376	Clear rig floor of misc. equipment - PJSM - Install mouse hole - LD Drill collars - HWDP & 4" DP f/ derrick Via mouse hole.
5/13/2011 0:00	8:15	9:30	1.25	9376	9376	Move pipe shed away from sub-base - Service rig.
5/13/2011 0:00	9:30	19:30	10	9376	9376	PJSM. Cont. to LD 4" DP f/ derrick via mouse hole.
5/13/2011 0:00	19:30	0:00	4.5	9376	9376	Suck out cellar and clean sumps and rig floor. Pump out waste tote in cellar area. Release rig at 24:00 hrs on 5/13/2011.

Exhibit 7-7 Construction and Completion Report

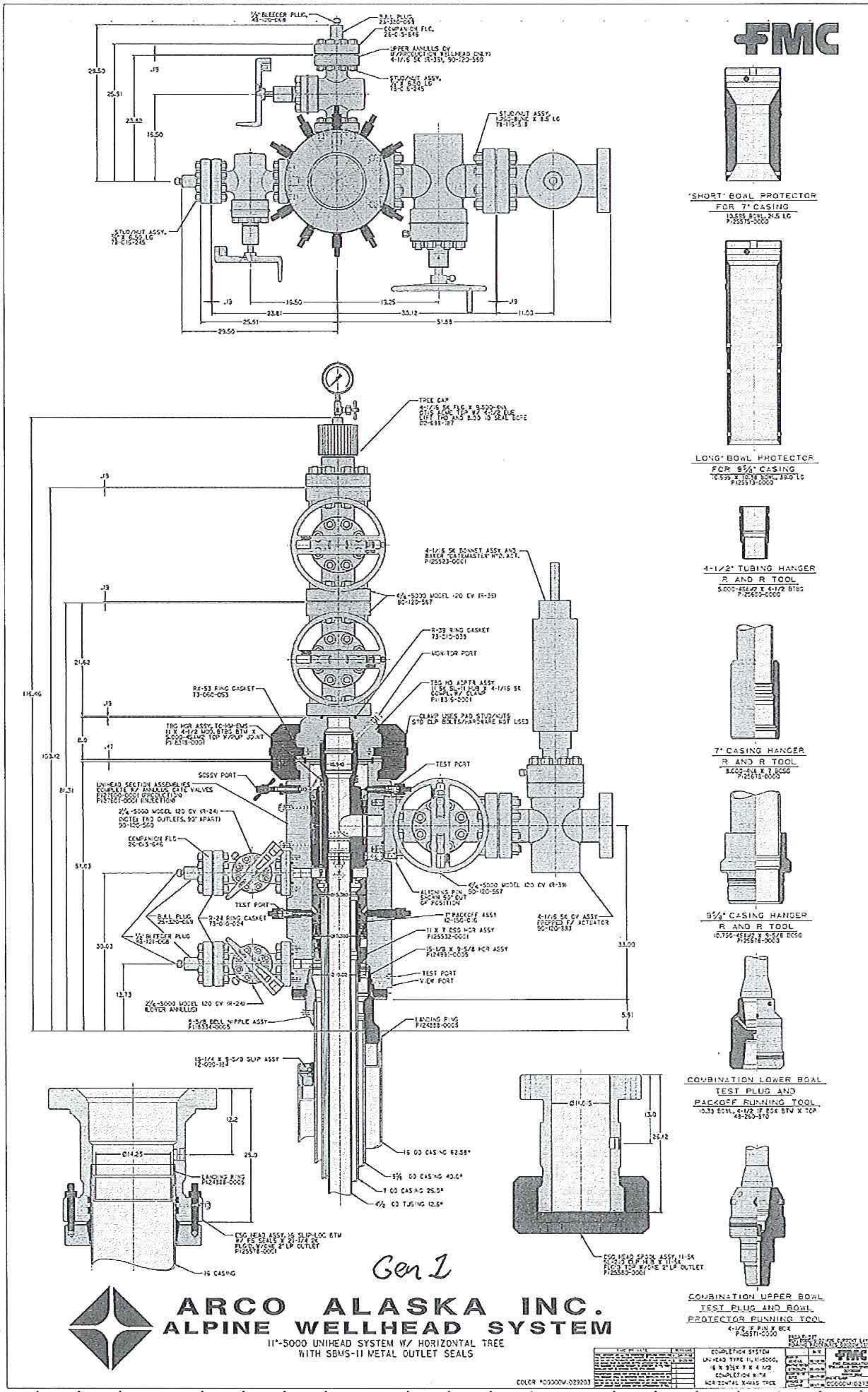
WD-02 Operational Events of Significance

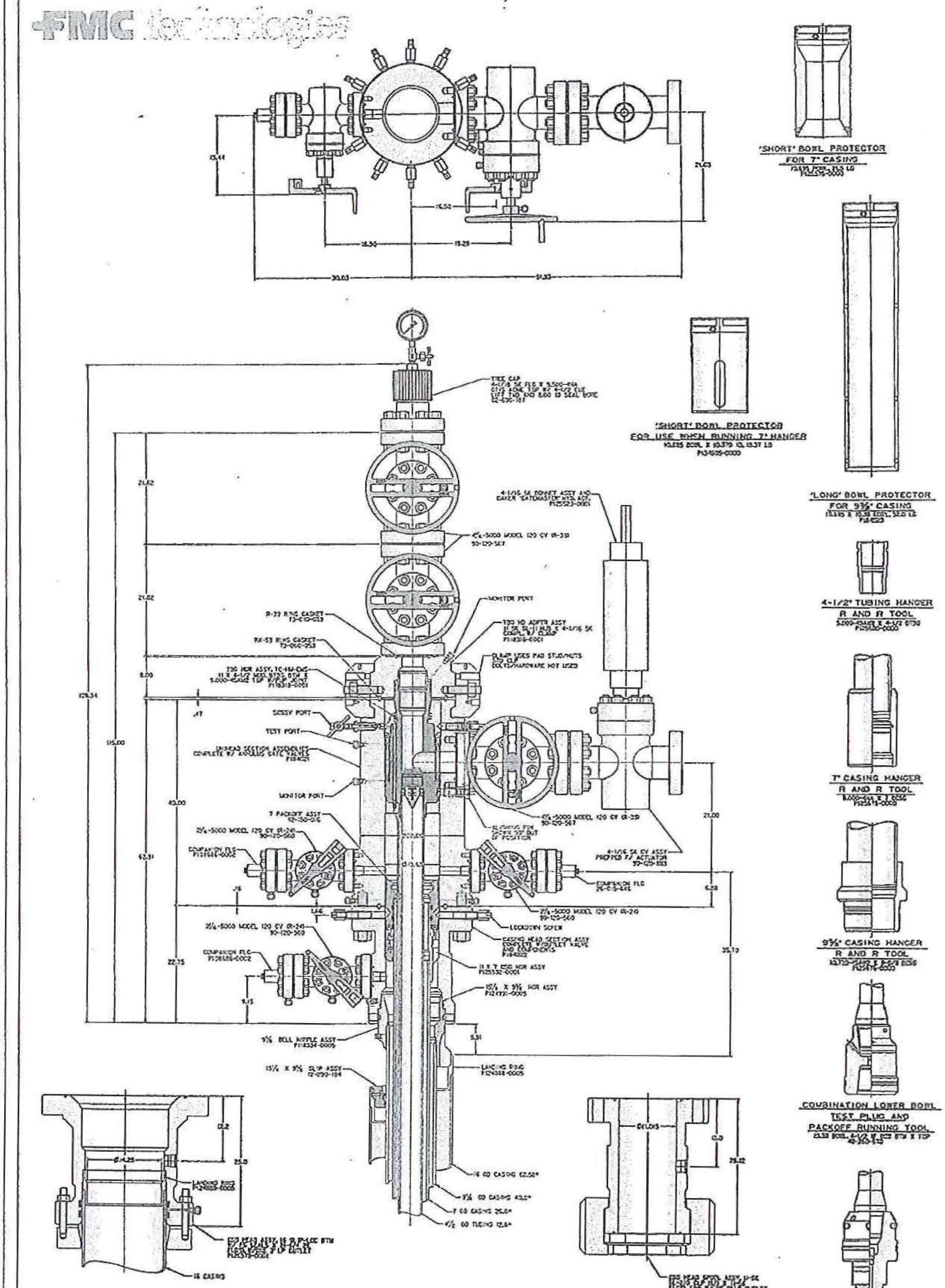
Year	Significant Operational Events
2018	Perform MITIA
	Log Caliper Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
2017	Perform MITIA
	Tag Fill
2016	Perform MITIA
	Log Caliper Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
2015	Perform MITIA
	Tag Fill
2014	Perform MITIA
	Log Caliper Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
2013	Perform MITIA
2012	Perform MITIA
	Log Caliper Survey
	Perform Water Flow Log
	Log Spinner Survey
	Flo-Seal Treatment to remediate suspected packer leak
2011	Perform MITIA
	Log caliper Survey (post RWO to replace tubing)
	Tag Fill
	Rig Workover to replace tubing
	Measure SBHP
2010	Perform MITIA
	Log Caliper Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
2009	Perform MITIA
2008	Perform MITIA
	Log Caliper Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
	Measure SBHP
2007	Perform MITIA
2006	Perform MITIA
	Log Caliper Survey
	Perform Water Flow Log
	Log Spinner Survey

Exhibit 7-7 Construction and Completion Report
WD-02 Operational Events of Significance

Year	Significant Operational Events
	Tag Fill
2005	Perform MITIA
	Tag Fill
2004	Perform MITIA
	Log Caliper Survey
	Log Temperature Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
2003	Perform MITIA
	Log Caliper Survey
	Log Temperature Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
2002	Perform MITIA
	Log Caliper Survey
	Log Temperature Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
	Measure SBHP
2001	Perform MITIA
	Log Caliper Survey
	Log Temperature Survey
	Perform Water Flow Log
	Log Spinner Survey
	Tag Fill
2000	Perform MITIA
	Log Caliper Survey
	Log Temperature Survey
	Perform Water Flow Log
	Perform Radioactive Tracer Survey
	Tag Fill

Exhibit 7-8 Wellhead Schematics





CONOCOPHILLIPS

ALPINE WELLHEAD SYSTEM

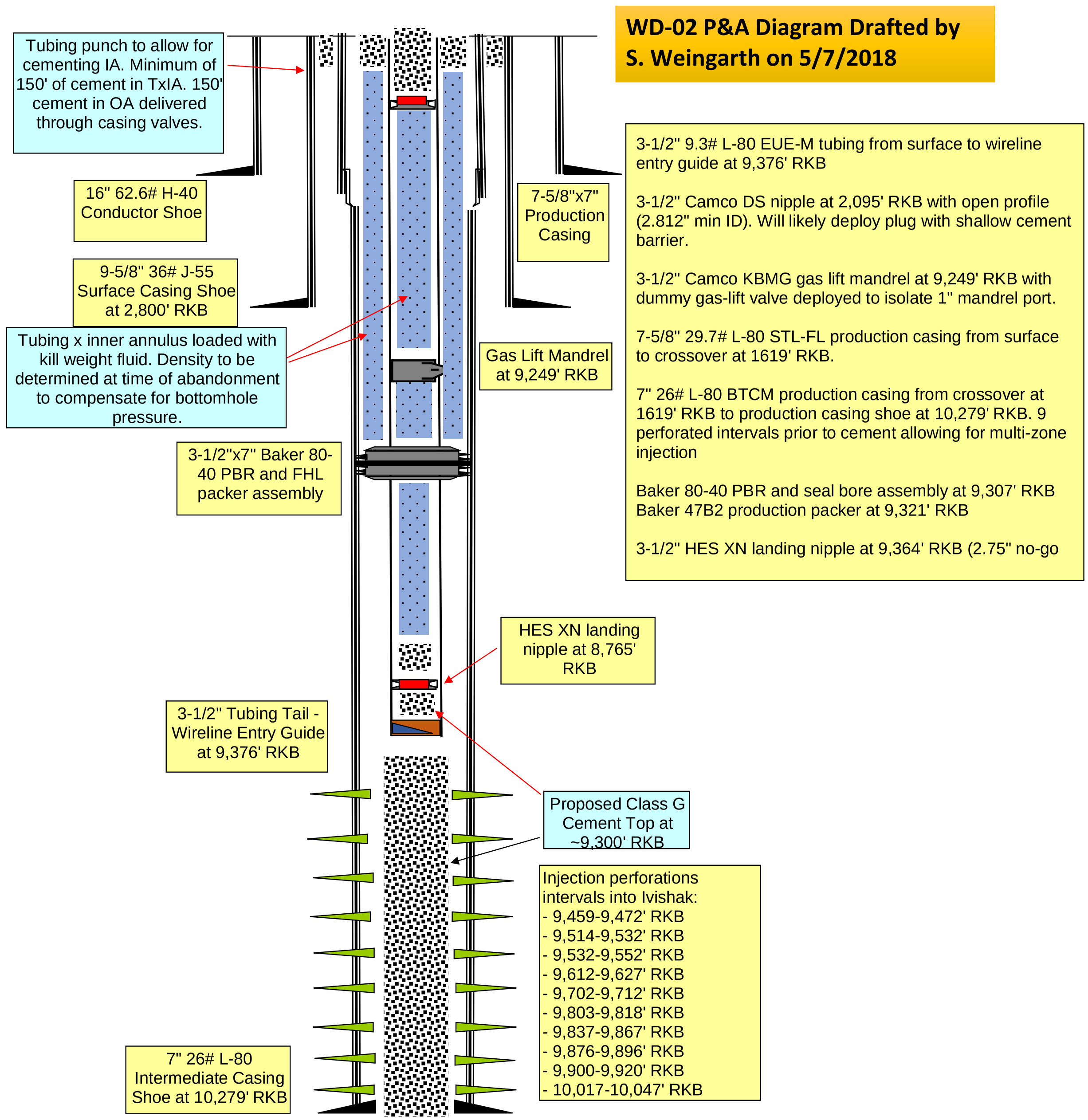
11"-5000 UNIHEAD SYSTEM W/ HORIZONTAL TREE WITH SBMS-11 METAL OUTLET SEALS

ConocoPhillips

119709

Gen 2

Exhibit 7-9 WD-02 Plug & Abandonment Diagram



8.0 BUSINESS FUNCTIONS

8.1 Business Description

As required by 40 CFR 144.31 (e)(8), a brief description of the nature of the business is provided below.

CPAI is a wholly-owned subsidiary of ConocoPhillips Company with corporate offices in Houston, Texas. The primary nature of its business is to engage in activities relative to the exploration and production of oil and gas. Corporate activities occur worldwide.

CPAI has been involved in the Alaskan oil business, through predecessor companies, since initial exploration of Prudhoe Bay leases in the 1960's. CPAI operates the KRU, CRU (Alpine Field) and has interests in other properties. Further information concerning CPAI businesses can be found in annual corporate reports, available online or upon request.

8.2 Surface Land Owners

As required by 40 CFR 144.31 (e)(9), the following list identifies owners of land within the CRU or within ¼ mile of the Unit boundary. The surface location of the well is approximately 8 miles north of the Village of Nuiqsut. Individual land owner information was provided by the Inupiat Community of the Arctic Slope.

The State of Alaska
Andrew T. Mack, Commissioner
State of Alaska, Department of Natural Resources
550 W. 7th Avenue, Suite 1400
Anchorage, Alaska 99501-1796

Kuukpik Corporation
Joseph Nukapigak, President
P.O. Box 89187
Nuiqsut, Alaska 99789

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

(b) (6) [redacted]

Bureau of Land Management
Karen Mouritsen, Acting State Director, Alaska State Office
222 W. 7th Avenue #13
Anchorage, Alaska 99513-7599

8.3 Existing Environmental Permits

As required by 40 CFR 144.31(e)(6), environmental permits that have been issued to CPAI for permanent facilities on the North Slope include, but are not limited to, the following.

APDES	AKG332025 Colville River Unit (CRU) Fieldwide (CD1-CD5) Discharge 003 - ASRC Mine Site Pit Dewatering Discharge 006 – Storm Water Discharge 007 – Mobile Spill Response Operator: ConocoPhillips Alaska, Inc. SIC Code: 1311
APDES	AKG332008 Kuparuk River Unit (KRU) Fieldwide Discharge 003 – Mine Site C, Mine Site E, Mine Site F Dewatering Discharge 006 – Storm Water Operator: ConocoPhillips Alaska, Inc. SIC Code: 1311
APDES	AKG332027 Greater Mooses Tooth Unit (GMT1 & GMT2) Discharge 006 – Storm Water Operator: ConocoPhillips Alaska, Inc. SIC Code 1311
APDES	AKG332039 Greater Mooses Tooth Unit 1 (GMT1) Discharge 005 – Hydrostatic Test Operator: ConocoPhillips Alaska, Inc. SIC Code 1311
RCRA	Generator No. AKR-00000-3806 Colville River Unit Operator: ConocoPhillips Alaska, Inc. SIC Code 1311
RCRA	Generator No. AKD991281023 Kuparuk River Unit Operator: ConocoPhillips Alaska, Inc. SIC Code 1311
UIC	Permit AK-1I010-B – CD1-01A Well Colville River Unit Operator: ConocoPhillips Alaska, Inc. SIC Code 1311
UIC	Permit AK-1I003-B – WD-02 Well

Colville River Unit
Operator: ConocoPhillips Alaska, Inc.
SIC Code 1311

Additionally, CPAI holds many Section 404 and state permits for North Slope facilities. Permits can be made available upon request.

8.4 Reporting

See Exhibit 8-1 designated authority for reporting to the EPA.

8.5 Financial Responsibility 40 CFR 144.52(a)(7) and 144.70 (f)(g)

ConocoPhillips, Alaska., Inc. is the operator of the Alpine Field which lies within the CRU. Operations is governed by an agreement between the lessees and the Arctic Slope Regional Corporation and the State of Alaska.

Per 40 CFR 144.52 (a)(7) the UIC Class I permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the EPA Director. A copy of the most recent submitted Safe Drinking Water Act (SDWA) UIC Financial Requirements documentation submitted on March 21, 2018 is provided in Exhibit 8-2.

ConocoPhillips, Alaska., Inc. has demonstrated the corporate commitment and financial resources necessary to implement a successful Class I Injection program at Alpine Field which lies within the CRU. This commitment is a long-term method of disposal for total field life, including proper well abandonment and final closure.

Exhibit 8-1 Duly Authorized Representative

ConocoPhillips
Alaska

Lisa R. Bruner
Vice President North Slope Operations & Development
P.O. Box 100360
Anchorage, AK 99510-0360
Phone: (907) 265-6513
Lisa.R.Bruner@conocophillips.com

October 10, 2016

Certified Mail
Return Receipt Requested
7016 1370 0000 0848 5789

Mr. Edward J. Kowalski, Director
Office of Compliance and Enforcement
U.S. Environmental Protection Agency
Region 10, (OCE-184)
1200 Sixth Avenue, Suite 900
Seattle, WA 98101

Re: Updated Duly Authorized Representatives
Colville River Unit CRU WD-02 Class I Permit Number AK-1I003-B
Colville River Unit CRU CD1-01A Class I Permit Number AK-1I010-A

Dear Mr. Kowalski:

I recently replaced Nicholas Olds as Vice President of North Slope Operations and Development for ConocoPhillips Alaska, Inc.

In accordance with 40 CFR 144.32(a) and 40 CFR 144.32(b) and acting in my capacity as Vice President of ConocoPhillips Alaska, Inc., I hereby designate the following positions as my duly authorized representatives having signature and certification authority for all reports, affirmations, compliance certifications, and other documents submitted by ConocoPhillips to the U.S. Environmental Protection Agency, Region 10 in connection with the following referenced ConocoPhillips UIC permits:

<u>Colville River Unit UIC Permit AK-1I003-B</u>
WNS Operations Manager, Operations & Maintenance Superintendent

<u>Colville River Unit UIC Permit AK-1I010-A</u>
WNS Operations Manager, Operations & Maintenance Superintendent

This designation replaces all prior designations for these UIC permits under the cited regulations. If you have questions regarding this designation, please contact Steve Brashear, Permitting Coordinator at (907) 263-4691.

Sincerely,

Lisa R. Bruner

ConocoPhillips

Michael Cooper
Director, Finance
Risk Management & Remediation
600 N. Dairy Ashford
Houston, TX 77079
Phone 832-486-3103

March 21, 2018

SDWA UIC Financial Requirements

VIA UPS OVERNIGHT

Regional Administrator
U.S. Environmental Protection Agency, Region 10
1200 Sixth Avenue, Ste 900
Seattle, WA 98101

Dear Sir or Madam:

The purpose of this letter is to provide demonstration of compliance with the requirements for financial responsibility for plugging and abandonment of Class I UIC wells as required by 40 CFR 144 (Underground Injection Control) regulations.

Facilities in Alaska under your respective jurisdictions include:

ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 99501
AKR 000 003 806
UIC Permit: #AK 1I010-A
Alpine (Well CD1-19A)

ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 99501
AKR 000 003 806
UIC Permit: #AK 1I003-B
Alpine (Well WD-02)

ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 99501
AKR 000 003 806
UIC Permit: #AK 1I010-A
Alpine (Well CD1-01A)

bcc: (w/o 10-K)
Ted Urbanek
Stephen G. Ellison (File Copy)
Michael Cooper (Record Copy)

Document Retention EF01: Equipment, Facilities and Property; Facility/System Design and Purchase/Lease/Sale: Underground Injection Control; Financial Assurance. Original Record Owner: Michael Cooper.

APPENDIX I

ConocoPhillips

LETTER FROM CHIEF FINANCIAL OFFICER

March 21, 2018

Regional Administrator
U. S. Environmental Protection Agency – Region 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101

Dear Sir or Madam:

I am the Chief Financial Officer of ConocoPhillips, 600 North Dairy Ashford Road, Houston, Texas 77079. This letter is in support of this firm's use of the financial test to demonstrate financial assurance, as specified in subpart F of 40 CFR part 144.

1. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is demonstrated through the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by the test is shown for each injection well: None.

2. This firm guarantees, through the corporate guarantee specified in subpart F of 40 CFR part 144, the plugging and abandonment of the following injection wells owned or operated by subsidiaries of this firm. The current cost estimate for plugging and abandonment so guaranteed is shown for each injection well:

ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 99501
AKR 000 003 806
#AK 1I010-A
Alpine (Well CD1-19A)
Plug and Abandon: $683,478.92

ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 99501
AKR 000 003 806
#AK 1I003-B
Alpine (Well WD-02)
Plug and Abandon: $683,478.92

ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 99501
AKR 000 003 806
#AK 1I010-A
Alpine(Well CD1-01A)
Plug and Abandon: $683,478.92

3. In States where EPA is not administering the financial requirements of subpart F of 40 CFR part 144, this firm, as owner or operator or guarantor, is demonstrating financial assurance for the plugging and abandonment of the following injection wells through the use of a test equivalent or substantially equivalent to the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by such a test is shown for each injection well: None.

4. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is not demonstrated either to EPA or a State through the financial test or any other financial assurance mechanism specified in subpart F of 40 CFR part 144 or equivalent or substantially equivalent State mechanisms. The current plugging and abandonment cost estimate not covered by such financial assurance is shown for each injection well: None.

This firm is required to file a Form 10-K with the Securities and Exchange Commission (SEC) for the latest fiscal year.

The fiscal year of this firm ends on December 31. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended December 31, 2017.

Alternative II

1.	a) Current plugging and abandonment cost	$2,050,437
	b) Sum of the company's financial responsibilities under 40 CFR Parts 264 and 265, Subpart H, currently met using the financial test or corporate guarantee	$0
	c) Total of lines a and b	$2,050,437
2.	Current bond rating of most recent issuance of this firm and name of rating service	Baa1 Moody's Investors Service
3.	Date of issuance of bond	03/08/2016
4.	Date of maturity of bond	03/15/2021 03/15/2026 03/15/2046

*5.	Tangible net worth (if any portion of the plugging and abandonment cost estimate is included in "total liabilities" on your firm's financial statements, you may add the amount of that portion to this line)	$30,730,423,000	
*6.	Total assets in U.S. (required only if less than 90% of firm's assets are located in U.S.)	$38,055,926,000	
		YES	NO
7.	Is line 5 at least $ 10 million?	X	_
8.	Is line 5 at least 6 times line 1(c)?	X	_
*9.	Are at least 90% of the firm's assets located in the U.S.? If not, complete line 10	_	X
10.	Is line 6 at least 6 times line 1(c)?	X	_

I hereby certify that the wording of this letter is identical to the wording specified in 40 CFR 144.70(f) as such regulations were constituted on the date shown immediately below.

CONOCOPHILLIPS

Don E. Wallette, Jr.
Executive Vice President, Finance, Commercial and Chief Financial Officer

March 21, 2018

APPENDIX II

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)
[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended **December 31, 2017**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission file number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

600 North Dairy Ashford
Houston, TX 77079
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **281-293-1000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $.01 Par Value	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. [x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. [ ] Yes [x] No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. [x] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [x] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]
Emerging growth company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). [ ] Yes [x] No

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $43.96, was $54.0 billion.

The registrant had 1,174,577,506 shares of common stock outstanding at January 31, 2018.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 15, 2018 (Part III)

APPENDIX III

Building a better
working world

Ernst & Young LLP
5 Houston Center
Suite 1200
1401 McKinney Street
Houston, TX 77010

Tel: +1 713 750 1500
Fax: +1 713 750 1501
ey.com

Report of Independent Accountants on Applying Agreed-Upon Procedures

Management of ConocoPhillips

We have audited, in accordance with standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of ConocoPhillips (the "Company") as of December 31, 2017 and 2016, and the related consolidated income statements, consolidated statements of comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and have issued our report with an unqualified opinion, thereon, dated February 20, 2018.

We have performed the procedures enumerated below, which were agreed to by management of the Company, solely to assist management with respect to the use of the financial test to demonstrate financial responsibility for plugging and abandonment, as specified in subpart F of 40 CFR part 144 (the "Regulation"). Management is responsible for determining compliance with the financial test that is presented on the basis specified by the Regulation. It is the Company's understanding these procedures are required by the U.S. Environmental Protection Agency, Region 10. The sufficiency of these procedures is solely the responsibility of the parties specified in this report. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

We have performed the following procedures with respect to the Chief Financial Officer's accompanying letter dated March 21, 2018, to the U.S. Environmental Protection Agency, Region 10 (the "Letter"):

1. We obtained the Company's schedule which calculates tangible net worth as of December 31, 2017. We recomputed the Company's schedule, and agreed amounts included in the calculation with amounts included in the Company's accounting records and the Company's audited consolidated financial statements referred to above, and found such amounts to be in agreement. We compared the dollar amount of tangible net worth as of December 31, 2017, from this schedule to the Letter (Item 5) and found it to be in agreement.

2. We obtained the Company's schedule which calculates total assets in the United States as of December 31, 2017. We recomputed the Company's schedule and agreed amounts included in the Company's calculation with amounts included in the Company's accounting records and audited consolidated financial statements referred to above, and found such amounts to be in agreement. We compared the dollar amount of total assets in the United States as of December 31, 2017, from this schedule to the Letter (Item 6) and found it to be in agreement.

3. With respect to the Letter (Item 9), we recomputed the percentage of assets located in the United States by dividing the amount included in the Letter (Item 6) by total assets, which we agreed to the Company's audited consolidated financial statements referred to above, noting that the recomputed percentage was less than 90%.

This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to and did not conduct an examination or review, the objective of which would be the expression of an opinion or conclusion, respectively, on the accompanying financial test to demonstrate financial responsibility for plugging and abandonment, as specified in the Regulation. Accordingly, we do not express such an opinion or conclusion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information and use of the Company and the U.S. Environmental Protection Agency, Region 10 and is not intended to be and should not be used by anyone other than these specified parties.

Ernst + Young LLP

March 21, 2018

APPENDIX IV

ConocoPhillips

GUARANTEE FOR PLUGGING AND ABANDONMENT

Guarantee made this 23rd day of March, 2017, by ConocoPhillips, a business corporation organized under the laws of the State of Delaware, herein referred to as guarantor, to the United States Environmental Protection Agency (EPA), obligee, on behalf of our subsidiary, ConocoPhillips Alaska, Inc., of 700 G Street, Anchorage, Alaska 99501.

Recitals

1. Guarantor meets or exceeds the financial test criteria and agrees to comply with the reporting requirements for guarantors as specified in 40 CFR 144.63(e).

2. ConocoPhillips Alaska, Inc. owns or operates the following Class I (non-hazardous) waste injection well(s) covered by this guarantee:

   ConocoPhillips Alaska, Inc.
   700 G Street
   Anchorage, AK 99501
   EPA I.D. #AKR 000 003 806
   EPA UIC Permit # AK-1I010-A
   Alpine(CD1-19A)
   Guarantee: Closure (Plug and Abandon)

   ConocoPhillips Alaska, Inc.
   700 G Street
   Anchorage, AK 99501
   EPA I.D. #AKR 000 003 806
   EPA UIC Permit # AK-1I003-B
   Alpine(WD-02)
   Guarantee: Closure (Plug and Abandon)

   ConocoPhillips Alaska, Inc.
   700 G Street
   ConocoPhillips Alaska, Inc.
   700 G Street
   Anchorage, AK 99501
   EPA I.D. #AKR 000 003 806
   EPA UIC Permit # AK-1I010-A
   Alpine(CD1-01A)
   Guarantee: Closure (Plug and Abandon)

3. "Plugging and abandonment plan" as used below refers to the plans maintained as required by 40 CFR part 144 for the plugging and abandonment of injection wells as identified above.

4. For value received from ConocoPhillips Alaska, Inc., guarantor guarantees to EPA that in the event that ConocoPhillips Alaska, Inc. fails to perform "plugging and abandonment"

of the above facility(ies) in accordance with the plugging and abandonment plan and other requirements when required to do so, the guarantor will do so or fund a trust fund as specified in 40 CFR 144.63 in the name of ConocoPhillips Alaska, Inc. in the amount of the adjusted plugging and abandonment cost estimates prepared as specified in 40 CFR 144.62.

5. Guarantor agrees that, if at the end of any fiscal year before termination of this guarantee, the guarantor fails to meet the financial test criteria, guarantor will send within 90 days, by certified mail, notice to the EPA Regional Administrator(s) for the Region(s) in which the facility(ies) is (are) located and to ConocoPhillips Alaska, Inc. that he intends to provide alternate financial assurance as specified in 40 CFR 144.63 in the name of ConocoPhillips Alaska, Inc. Within 30 days after sending such notice, the guarantor will establish such financial assurance if ConocoPhillips Alaska, Inc. has not done so.

6. The guarantor agrees to notify the Regional Administrator, by certified mail, of a voluntary or involuntary case under Title 11, U.S. Code, naming guarantor as debtor, within 10 days after its commencement.

7. Guarantor agrees that within 30 days after being notified by an EPA Regional Administrator of a determination that guarantor no longer meets the financial test criteria or that he is disallowed from continuing as a guarantor of plugging and abandonment, he will establish alternate financial assurance, as specified in 40 CFR 144.63, in the name of ConocoPhillips Alaska, Inc. if ConocoPhillips Alaska, Inc. has not done so.

8. Guarantor agrees to remain bound under this guarantee notwithstanding any or all of the following: amendment or modification of the plugging and abandonment plan, the extension or reduction of the time of performance of plugging and abandonment or any other modification or alteration of an obligation of ConocoPhillips Alaska, Inc. pursuant to 40 CFR part 144.

9. Guarantor agrees to remain bound under this guarantee for so long as ConocoPhillips Alaska, Inc. must comply with the applicable financial assurance requirements of 40 CFR part 144 for the above-listed facilities, except that guarantor may cancel this guarantee by sending notice by certified mail, to the EPA Regional Administrator(s) for the Region(s) in which the facility(ies) is (are) located and to ConocoPhillips Alaska, Inc., such cancellation to become effective no earlier than 120 days after actual receipt of such notice by both EPA and ConocoPhillips Alaska, Inc. as evidenced by the return receipts.

10. Guarantor agrees that if ConocoPhillips Alaska, Inc. fails to provide alternate financial assurance and obtain written approval of such assurance from the EPA Regional Administrator(s) within 90 days after a notice of cancellation by the guarantor is received by both the EPA Regional Administrator(s) and ConocoPhillips Alaska, Inc., guarantor will provide alternate financial assurance as specified in 40 CFR 144.63 in the name of ConocoPhillips Alaska, Inc.

11. Guarantor expressly waives notice of acceptance of this guarantee by the EPA or ConocoPhillips Alaska, Inc. Guarantor also expressly waives notice of amendments or modifications of the plugging and abandonment plan.

I hereby certify that the wording of this guarantee is identical to the wording specified in 40 CFR 144.70(f).[1]

Effective date: March 23, 2017

CONOCOPHILLIPS

D E Wallette Jr

Don E. Wallette, Jr.
Executive Vice President, Finance, Commercial and Chief Financial Officer

KIM A HARTENSTEINER
Notary Public, State of Texas
Comm. Expires 08-03-2018
Notary ID 125785587

STATE OF TEXAS)
)
COUNTY OF HARRIS)

On March 23, 2017, before me, Kim A. Hartensteiner, a Notary Public personally appeared Don E. Wallette, Jr., personally known to me to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

WITNESS my hand and official seal.

Kim A. Hartensteiner
Notary Public
My Commission Expires: 08-03-2018

(SEAL)

[1] Except as modified in Item 2 above to reflect that the injection well is Class I (non-hazardous).

9.0 SUMMARY AND CONCLUSIONS

The operation of the Class I WD-02 injection well will continue to enhance development of the CRU by serving as a reliable disposal point primarily for camp domestic wastewater/graywater, and for produced water disposal should the need occur. Summarized below are the major conclusions reached within the application regarding the management of Alpine wastes in a manner that protects human health and the environment.

- The current disposal system meets the CPAI objective of minimum storage and discharge of production and domestic wastes. WD-02 and CD1-01A Class I wells will additionally reduce safety and environmental risks to the area, in part because they will reduce handling, unmanageable storage, transportation activities, and will provide for permanent disposal in a controlled manner.

- Geologically, the subsurface environment is very compatible with the disposal process. The same type of fluids that have been injected into WD-02 have been successfully disposed of in the Sag River and Ivishak formations for many years. Volumetrically, the waste volume over the remaining life of the project is consistent with other long-life disposal operations on the North Slope.

- No wells penetrate the area of review within the injection and confining intervals so no corrective action plans are necessary.

- No development or exploratory wells are projected to penetrate the disposal zone. If this should happen, they will be cased, cemented, and the wellbores sealed so no wastes escape the disposal and confining zones.

- The confinement risks summarized in Section 6.0 discuss issues involved with disposal for the remaining life of the project, as if all camp domestic wastewater/graywater went only to WD-02. It was determined that the probability of injectant escaping the injection zone was very small. CPAI risk assessment concluded the risk of injectant escaping was assessed very low.

- The WD-02 well is located in the Alpine Field, and the EPA has previously determined that no underground sources of drinking water (USDW) exist in the Alpine Field. Accordingly, renewal is requested for three existing waivers of UIC program requirements.

    1. The performance standard which prohibits fracturing the injection zone. 40 CFR 146.13(a)(1).
    2. The requirement to sample and characterize formation fluids and rock matrix. 40 CFR 146.12(e)(4)–(5) and 40 CFR 146.14(a)(8).
    3. The stipulation to perform ambient monitoring above the injection zone. 40 CFR 146.13(b)(1) and (4) and 40 CFR 146.13(d).

- WD-02 was constructed to inject mud, slurries, and other Class I wastes, and has been in successful operation for nineteen years. It has injected 6.1 million barrels of camp domestic wastewater/graywater and produced water. It has met all Class I mechanical regulatory and performance requirements.

  CPAI requests that the EPA allow the well to continue to operate as in the past.

  1. Annular pressure testing at 3500 psi and the normal regulatory injection pressure limit would be at 3200 psi, with excursions to 5000 psi.
  2. Annulus pressures visually monitored when injection is occurring.
  3. A mechanical integrity test of the inner annulus performed annually.
  4. A temperature, oxygen activation, borax log, or other equivalent fluid confinement tool run every other year to demonstrate the lack of fluid movement in a channel behind pipe.
  5. A caliper log run every other year to determine the condition of the tubing.

- Approved waste streams generated outside of the Colville River Unit, including CPAI or third party wastes generated at other North Slope locations, will be accepted for disposal under certain circumstances as described in Section 2.6.

- Sufficient CPAI experience exists to assure that proper well operation will occur. Systems are in place for proper operator training to monitor and control all surface equipment, guarantee well mechanical integrity, and to use the waste manifesting system as intended. This is further backed up by competent technical staff professionals, a SPCC Plan, and a spill contingency plan should that be required.

- The manifesting system and the Alpine Waste Analysis Plan ensure proper handling of Class I and batch processed wastes. The procedures have been successfully used at Alpine and other CPAI facilities for years.

- CPAI demonstrates the financial resources necessary for proper operation of the facility and plugging and abandonment of the well.

CPAI requests that the EPA renew and extend services under the existing permit AK-1I003-B for the Class I disposal well WD-02. CPAI also requests that the existing WD-02 monitoring and operating practices currently in use be incorporated into the renewed Class I permit.

Appendix A

ConocoPhillips
Alaska, Inc

P.O. Box 196860
Anchorage, Alaska 99519-6105

Waste Analysis Plan
Alpine Class I Underground Injection Wells WD-02 & CD1-01A
Western North Slope - Alaska

Underground Injection Control Permits AK-1I003-B & AK-1I010-A

Revision 6

May 2017

STATEMENT OF CERTIFICATION

This report is hereby certified in accordance with the requirements of Part I.E.15 of EPA Permits #AK-1I003-B & AK-1I010-A

"I certify under the penalty of law that I have personally examined and I am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment."

Misty Alexa

22 MAY 2017

Misty Alexa | Date

Manager, Western North Slope Operations

RECORD OF REVISIONS

REVISION NUMBER	REVISION DATE	SUMMARY OF CHANGES
0	8/97	Preliminary version, issued with permit application
1	11/01	General update and reorganization of contents to reflect current operations and procedures.
2	12/02	• Updated corporate name and position titles • Sec. 2.5.2 and Exhibit 4: Modified waste stream sampling frequency • Exhibit 1: Updated wastewater plant designation (M4) • Exhibit 3: Revised sewage/sludge classification from RCRA exempt to non-exempt, non-hazardous • Exhibit 8: Attached revised North Slope Manifest form
3	5/07	Exhibit 8: Attached 2005 revised North Slope Manifest form Added Statement of Certification Form Updated SOP numbers Updated position titles
4	7/07	Updated to include both WD-02 and CD1-19A wells Added references to CD1-19A throughout the text. Added production solids and production facility fluids to Waste Stream List Updated Waste Disposal Flow Schematic
5	02/15	General update to reflect current operations and procedures Changed references to CD1-19A from CD1-01A Clarified "fingerprint" sampling frequency Changed references to Permit #AK1I003-B for WD-02 Added "grout" as a synonym for "cement" Deleted test methods for RCRA hazardous waste characteristic of Reactivity; updated other analytical procedures Exhibits 4 & 5: Updated sampling requirements and methods Exhibit 8: Updated to February 2013 revised North Slope Manifest form Removed empty container rinseates as RCRA-exempt waste and included in the non-exempt category
6	3/17	Updated Exhibit 1 Alpine Waste Disposal Flow Schematic and add waste streams to Exhibit 3 Typical Alpine Waste Streams

Contents

1.0 INTRODUCTION

1.1 Purpose

This Waste Analysis Plan (WAP) outlines procedures for classifying, sampling, and analyzing wastes prior to disposal at the Alpine Class I Injection Wells WD-02 and CD1-01A. ConocoPhillips Alaska, Inc. (CPAI) has prepared this WAP to fulfill the requirements of Section I.E.9.f of Underground Injection Control (UIC) Permits AK-1I003-B and AK-1I010-A. Well CD1-01-A has replaced well CD1-19A.

1.2 References

The following procedures and resources are incorporated by reference.

- Alpine Standard Operating Procedure (SOP) W-008: Hazardous Waste Management
- Alpine & Kuparuk SOP T-006: Field Sampling
- The CPAI *Alaska Waste Management Plan*
- The *Alaska Waste Disposal and Reuse Guide*[1](RedBook)
- The *North Slope Environmental Field Handbook*[1]

1.3 Responsibilities and Training Requirements

All Alpine Personnel

- Comply with applicable waste management procedures and policies.
- Contact Supervisor and/or CPAI Environmental staff if there are any questions about waste management.

  Required training

- Basic Alpine Environmental Awareness training (part of initial orientation).

Waste Generators

A waste generator is the person responsible for a process or activity that produces waste (does not apply to routine sanitary and domestic wastes). Generators may include, but are not limited to:

- Drilling superintendent, tool pusher, and mud engineer.
- Maintenance shop supervisor.
- Utility plant operator.
- Health, Safety, and Environmental (HSE) staff.
- Production facility operator.

---

[1] See Section 5 of this WAP for complete citation.

Generators are expected to:

- Classify wastes in accordance with the *Alaska Waste Disposal & Reuse Guid*e (RedBook) and instructions provided by CPAI.
- Oversee management of all wastes at workplace, including wastes entering disposal system through sumps, mud pits, or holding tanks.
- Uses the North Slope Manifest when transporting batch wastes (see Section 3)

  Required training

- *Alaska Waste Disposal and Reuse Guide* (RedBook) Certification training[1] as directed by supervisor and/or CPAI Environmental representative.

Injection Facility Operator

- Review all incoming North Slope Manifests as described in Section 3 of WAP.
- Maintain records of injection volume and pressure as specified in UIC permit.

  Required training

- *Alaska Waste Disposal and Reuse Guide* (RedBook) Certification training[1].
- On-the-job UIC permit conditions/compliance training.

Alpine Environmental Coordinator

- Coordinates UIC training for designated field staff.
- Audits North Slope manifests and waste handling procedures.
- Tracks wastes on disposal log and/or manifest (see Section 3).
- Coordinates sampling and analysis as specified in Section 2 of WAP.
- Helps resolve questions about waste classification and management options (in consultation with other CPAI Environmental staff).
- Coordinates agency reporting and correspondence.

  Required training

- *Alaska Waste Disposal and Reuse Guide* (RedBook) Certification training[1].
- UIC permit conditions/compliance familiarity.
- RCRA generator requirements familiarity WAP conditions/compliance familiarity.

CPAI Environmental and Legal Staff, Anchorage

- Assists with agency reporting and correspondence as needed.
- Contacts EPA to resolve questions about the UIC permit.
- Assists in developing UIC and WAP training materials.
- Assists in updating the WAP.
- Prepares permit applications and renewals.

1 Standardized course provided by CPAI and BP Exploration (Alaska) Inc.

1.4 Description of Facility

Wells WD-02 and CD1-01A are operated by CPAI in the Colville River Unit (CRU) on Alpine Pad CD-1. The injection zone for WD-02 is located between approximately 8650 and 9720 feet below the ground surface. Wastes are confined in the injection zone by a 1500-foot thick impermeable rock layer. The injection zone for CD1-01A is located between approximately 8750 and 9000 feet below the ground surface. Wastes are confined in the injection zone by a 1500-foot thick impermeable rock layer.

The Environmental Protection Agency (EPA) has determined that there are no underground sources of drinking water in the area. A complete description of the disposal process and the injection facility is contained in the respective UIC Permit applications which are saved on the CPAI Share Point and Live-Link.

Exhibit 1 is a schematic waste flow diagram for Alpine. A complete description of the disposal process and the injection facility is contained in the UIC permit applications.

1.5 Criteria for Underground Injection

Wastes must meet the following criteria for underground injection.

1. The waste is included in a "generic" waste stream category in the Class I permit application (see WAP Exhibit 2). Any waste that does not fit into one of these broad categories requires approval from EPA.

2. The waste is classified as non-hazardous or exempt from hazardous waste management regulations under the Resource Conservation and Recovery Act (RCRA). See WAP Section 2, below.

3. The waste meets the injection facility's safety and operational criteria.

4. Disposal is properly documented (see WAP Section 3).

1.6 Description of Alpine Wastes

1.6.1 Waste Volume and Composition

Exhibit 2 summarizes the injection streams that were described by CPAI on the Alpine UIC permit applications.

Alpine Waste Composition (Projected)

Component	Approx. % of Total
Domestic sewage/graywater	53
Drilling muds and other rig fluids	27
Well and process fluids	16
Produced water	3
Drill cuttings, frac sand, vessel sludge/sand, etc.	<1
Snowmelt, other non-hazardous industrial wastes	0.3

1.6.2 Waste Streams

All oil and gas operations on the North Slope generate similar types of wastes. These can be grouped into broad categories, or "waste streams", which are reasonably consistent from one location to another, and over time. Exhibit 3 lists waste streams likely to be injected at Alpine.

1.6.3 Hardlined and Batch Wastes

Most Alpine wastes are pumped from the source to the injection facility through permanent flow lines. These hardlined wastes may flow to the well continuously, by level-activated pumps, or by manually activated pumps.

Batch wastes are generated by intermittent processes that are not permanently connected to the injection system. These processes include, but are not limited to, spill cleanups, impoundment dewatering, drill cuttings, and sewage from rig camps and enviro-vacs. Batch wastes must be physically transported to the disposal system by vacuum truck or other external means as illustrated in Exhibit 1. Less than one percent of the total waste volume is delivered in batch loads.

1.6.4 Waste Generating Area

Wastes injected in WD-02 and CD1-01A are associated with oil and gas exploration, production, and support activities within the Colville River Unit (CRU). On a case-by-case basis, CPAI will evaluate RCRA-exempt or non-hazardous wastes generated by companies outside of the CRU, in connection with oil and gas exploration, production, and support. All wastes must be adequately characterized to ensure that they meet the injection criteria outlined in Part 1 (above).

2.0 WASTE ANALYSIS PROCEDURE

Using the criteria outlined in this section, wastes will be evaluated for injection in the Alpine Class I disposal wells.

2.1 Waste Classification

All wastes must be classified before they are introduced into the disposal system. Wastes will be classified by a generator who has completed the North Slope Waste Management Certification Program. All classifications are subject to confirmation by the Alpine Environmental Coordinator.

The three categories of waste are:

- RCRA exempt,
- Non-exempt, non-hazardous, and
- RCRA hazardous.

Wastes must be classified before they are approved to be commingled with other materials in sumps, pits, or containers.

2.2 Exempt Wastes

RCRA exempt waste streams (Exhibit 3) are approved for injection without prior sampling and analysis, providing the activity is clearly one identified as generating exempt wastes. The same material, generated by a non-exempt process, may be regulated as hazardous waste.

All processes and facilities are subject to audit by the Environmental staff to verify that waste-generating activities are accurately described as RCRA-exempt.

Exempt wastes may have properties that make them dangerous to handle. Therefore, they must meet all applicable safety and operational restrictions at the injection facility.

2.3 Non-Exempt Wastes

Non-exempt wastes must be characterized before they can be injected to confirm that they are non-hazardous and allowed by the permit.

2.3.1 Characterization without Analysis

Sampling is not always necessary to characterize a waste.

Commercial chemical products: Commercial chemical products can sometimes be adequately characterized by generator knowledge in accordance with 40 CFR 262.11(c)(2). Generator knowledge may be based on a Materials Safety Data Sheet (MSDS) or other applicable data. Before sending the material to the injection well, the generator should provide a copy of the MSDS (or other data) to the Environmental Coordinator for review.

CPAI maintains a computerized MSDS database for many products used on the North Slope.[1] MSDSs can also be obtained from the product manufacturer, or the contractor providing the material. If the MSDS for a product clearly indicates that it is not RCRA hazardous when discarded, and it has not been mixed with any unknown material, the waste will generally be approved for injection without further analysis.

Generator knowledge is also sufficient to characterize seawater, fresh water, or sanitary/domestic waste (raw or treated sewage) that has not been mixed with anything else.

Existing Data: Wastes submitted under a "current" waste stream (see following section) do not have to be analyzed on a load-by-load basis. At the discretion of the Environmental Coordinator, data from other North Slope locations may be used to characterize a common, recurring waste stream. Recurring waste streams will be fingerprinted annually.

2.3.2 Characterization by Analysis

Sampling and laboratory analysis will be required for any non-exempt waste that either (a) does not fit into a current, established waste stream, or (b) cannot be characterized by generator knowledge to the satisfaction of the Alpine Environmental Coordinator. Exhibit 4 summarizes sampling and analytical requirements.

Non-exempt wastes will be evaluated as follows.

Initial characterization. A representative sample of the waste stream will be collected by the Environmental Coordinator, and sent to a commercial laboratory for hazardous waste characterization. Parameters for initial characterization will include the hazardous waste characteristics listed in Exhibits 6 and 7 plus basic indicator properties such as appearance. Toxicity parameters (Exhibit 7) will be selected at CPAI Environmental staff's discretion based on the contaminants likely to be present in a given waste stream. They will generally include TCLP volatiles, semi-volatiles, and metals, but not pesticides or herbicides. Analytical parameters are listed on Exhibit 4. Methods, sample containers, and holding times are summarized on Exhibit 5. Results will be compared to the hazardous waste characteristic limits in Exhibits 6 and 7.

> More than one sample may be necessary to characterize the waste stream, particularly if there are several different sources. Waste streams should be re-sampled if the waste-generating process changes over time.
>
> Once initial characterization is complete, testing requirements can be reduced for subsequent loads of the same waste stream. As long as the waste stream remains consistent, testing will consist of periodic analysis as indicated on Exhibit 4.

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1 This sitehawk database is currently accessible on the CPAI Intranet Site.

In some cases, due to matrix effects or laboratory precautions, samples may require dilutions that will result in sample reporting levels exceeding regulatory thresholds. In this case a description of the process generating the waste may be use to document that the constituent of interest is not reasonable expected to be present in the waste. Otherwise the waste will be presumed to be hazardous.

Fingerprinting. "Fingerprinting" involves testing a sample for indicator parameters to confirm that the waste stream remains non-hazardous over time. Fingerprinting can "flag" significant changes in the waste-generating activity. Fingerprint parameters and acceptable ranges are indicated on Exhibit 4. Except for benzene or other specific constituent analyses, most fingerprint tests can be done on-site using simple field techniques. In some cases, due to matrix effects or laboratory precautions, samples may require sample dilutions that will result in sample reporting levels exceeding regulatory thresholds. In this case, a description of the process generating the waste may be use to document that the constituent of interest is not reasonable expected to be present in the waste. Otherwise the waste will be presumed to be hazardous.

Recurring waste streams (except for those characterized by MSDS) will be fingerprinted - annually. This schedule and the parameters for analyses are subject to re-evaluation based on the users' knowledge of the waste.

2.4 Sampling Methods

Samples for waste characterization or fingerprinting will be collected by the Environmental Coordinator, or other qualified personnel. In most cases, these will be grab samples taken directly from the waste container. Wastes from different sources should always be segregated until sample results are received.

Containers. Exhibit 5 shows the minimum sample volumes and container types required for various analyses. New, pre-cleaned containers should be obtained from the analytical lab or a reputable supplier of laboratory goods.

Representative Samples and Composites. For initial characterization, waste stream samples from different locations should not be combined for testing unless the waste-generating processes are virtually identical. Each source should be analyzed separately to establish a "track record" for Alpine. This is especially true for waste streams such as sump fluids, facility wash waters, and lubrication oils, which may come from several different locations.

For fingerprint analysis of established waste streams, composite samples from several sources are acceptable, providing all wastes are derived from the same process.

Waste should be visually examined, if possible, before sampling. If it appears homogeneous, a composite sample may be taken. If the waste appears stratified or contains more than one phase (sludge plus liquid, for instance), each layer or phase should be sampled and analyzed separately. The approximate volume of each phase should be estimated. Different phases may be combined into a single composite if (1) the phases cannot or will not be separated for disposal and (2) samples from each phase are combined in proportion to their estimated volume in the container. (Note that if one phase proves hazardous and the other does not, the entire container must be handled as a hazardous waste.)

If a composite sample shows any RCRA hazardous waste characteristics, individual containers must be analyzed to isolate the source of hazardous waste. If there are measurable levels of toxic components (Exhibit 7) in the composite, the TCLP concentration must be multiplied by the number of samples in the composite. If this level exceeds RCRA limits (Exhibit 6), the individual containers must be evaluated to isolate the hazardous material; otherwise, the entire batch is a hazardous waste.

Sampling Tools. Various sampling tools are available. For fluids in drums or relatively shallow sumps, a coliwasa may be most effective. For larger containers, such as vac trucks or Tiger tanks, it may be necessary to pump or siphon a sample through clean tubing into a sample container. Equipment may have to be improvised for a particular situation. Sludges or solids may be sampled with clean hand tools or coring devices (such as clean PVC tubing).

2.5 Sampling Frequency

2.5.1 Exempt Waste Streams

Exempt waste streams are not sampled. However, to ensure that wastes have been properly characterized as RCRA-exempt, all generators, transporters, and receivers must maintain active status in the North Slope Waste Certification Program. In addition, manifests will be examined regularly by the Environmental Coordinator, and waste-generating processes are subject to ongoing oversight and review by CPAI environmental staff.

2.5.2 Non-Exempt Waste Streams

Non-exempt waste streams will undergo an initial characterization for hazardous waste characteristics in accordance with the methods listed on Exhibit 5. After the initial characterization, each of these waste streams will be fingerprinted at least annually in subsequent years. At the Environmental Coordinator’s discretion, waste streams may be sampled more frequently.

Generator knowledge and/or manufacturer’s data may be substituted for laboratory analysis as appropriate.

3.0 RECORD KEEPING AND DOCUMENTATION

According to UIC Permit Section I.E.9.b, CPAI must keep records concerning the nature and composition of all injected fluids until three years after the well is plugged and abandoned. Manifests, daily disposal logs, and analytical records should be kept on-site at Alpine for at least one year; then they may be forwarded to central files in Anchorage.

3.1 Manifests

A North Slope Manifest (Exhibit 8) will be used to account for materials that are delivered by batch into the facility waste disposal systems. This includes each batch load of waste delivered to the M1 utility module through the truck hookup.

Manifests may only be completed and signed by generators, transporters, or receivers who have satisfactorily completed The North Slope Waste Management Certification Program described in the *Alaska Waste Disposal and Reuse Guide* (RedBook). General instructions for completing the manifest are provided in the *Alaska Waste Disposal & Reuse Guide*.

3.2 Recordkeeping Requirements

Records relating to this WAP are retained as follows:

Record	Custodian	Location
Sampling and analytical records	Alpine Environmental Coordinator, Alaska Clean Seas Technicians	Alpine HSE Files
Waste Certification (Redbook) training records	Alpine HSE Assistant	Alpine HSE files
Original signed North Slope manifests	Alpine, Environmental Coordinator, Alpine HSE Assistant	Alpine HSE files

- Sampling and analytical records include results of initial characterization and subsequent fingerprint analyses, analytical data, or other relevant documents
- Redbook training records document “certified” generators, transporters, and receivers

4.0 QUALITY ASSURANCE AND QUALITY CONTROL

4.1 Field

4.1.1 Sample Handling and Custody Procedures

Sampling procedures are outlined in Section 2.4. For each analytical method, the appropriate containers, preservation methods, and holding times are outlined in Exhibit 5. Before collecting or sending any samples, field personnel should always contact the receiving laboratory to confirm procedures and to make the necessary logistical arrangements. Trip blanks are required for volatile sample analysis (e.g., benzene, toluene, etc.). The laboratory will indicate whether trip blanks are required.

Each container will be labeled with the sample number, date and time sampled, and sampler's initials. A Chain-of-Custody form will accompany each sample, and will be verified and signed by each person handling the sample until its final disposition.

4.1.2 Quality Control Samples

QA/QC for on-site analysis (pH, flash point, field screening) will include, at a minimum:

- Equipment calibration in accordance with manufacturer's instructions
- Periodic duplicate testing to verify consistency

The Environmental Coordinator should keep a file of calibration records and any duplicate testing performed on-site.

4.1.3 Training

As described in Section 1, an appropriate level of training will be provided for all personnel involved with waste generation, transportation, and disposal at Alpine.

Training records will be maintained by the CPAI Training Department and/or by the contract employee's company.

4.2 Laboratories

Commercial laboratories are expected to maintain QA/QC plans which will be provided to CPAI upon request. Laboratories will be asked to provide the following QA/QC documentation along with sample results.

- Method blank
- Surrogate recovery (if applicable)
- Matrix spike and matrix spike duplicate results (if applicable)
- Duplicate results

If fewer than 20 samples are sent to the laboratory, batch QC reports are acceptable.

4.2.1 Audits

CPAI may, at any time, conduct audits of contract laboratories as well as internal audits of field procedures at Alpine.

4.2.2 Data Reports

Laboratory reports will be reviewed by the Alpine Environmental Coordinator with assistance, as required, by the CPAI Environmental staff in Anchorage. Each report will be reviewed for:

- Correct sample number and location
- Correct analytical parameters
- Values within acceptable ranges
- Any reported QA/QC discrepancies

5.0 REFERENCES

The following references are available either at the Alpine Environmental office or through the CPAI Permits and Sciences Department in Anchorage.

BP Exploration (Alaska) Inc. (BPXA) and ConocoPhillips Alaska, Inc. May 2015. *Alaska Waste Disposal and Reuse Guide.* [Note: this volume is subject to periodic update and revision; the most current version will be kept on-site.]

BPXA and ConocoPhillips Alaska, Inc. December 2015. *North Slope Environmental Field Handbook.* [Note: this volume is subject to periodic update and revision; the most current version will be kept on-site.]

ConocoPhillips Alaska, Inc. 2014. *Alaska Waste Management Plan*. [Note: this volume is subject to periodic update and revision; the most current version will be kept on-site.]

U.S. Environmental Protection Agency (EPA). July 6, 1988. *Regulatory Determination of Oil and Gas and Geothermal Exploration, Development, and Production Waste.* Federal Register Vol. 53 No. 129.

U.S. Environmental Protection Agency (EPA). March 22, 1993. *Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy.*

U.S. EPA. January 2002. *Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations*. EPA Publication 530-K-01-004.

EXHIBIT 1
ALPINE WASTE DISPOSAL FLOW SCHEMATIC

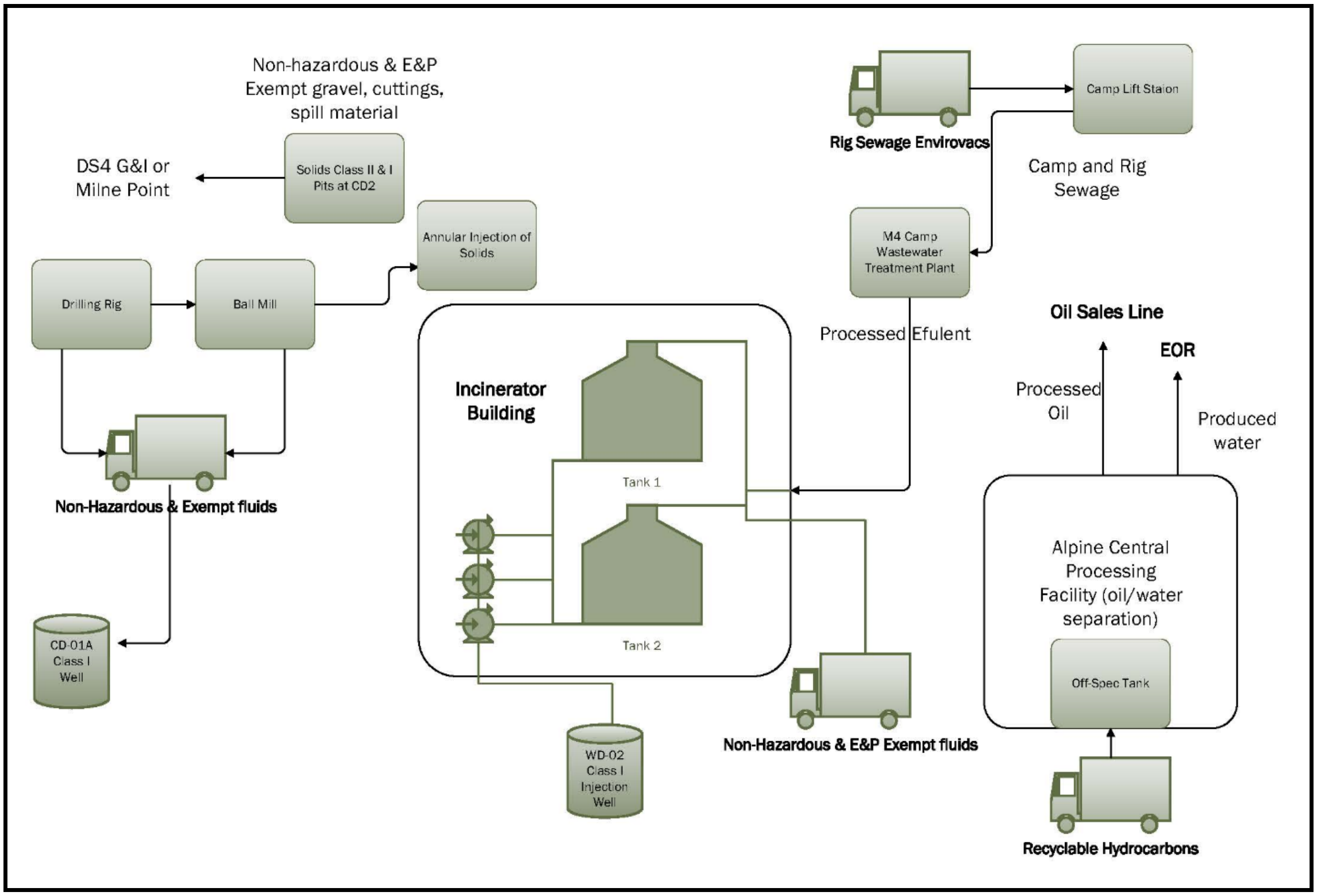

EXHIBIT 2
WASTE STREAMS DESCRIBED IN PERMIT APPLICATION

The following wastes were identified on Alpine's UIC application or are documented as changes in the "record of revisions" table.
For this exhibit, they have been re-arranged in alphabetical order and edited for brevity.

Waste	General Description ***Note:*** *Wastes on this list* ***are not*** *automatically approved for injection. Each must be evaluated for disposal in accordance with Section 2 of the Waste Analysis Plan*.
Acid	Used widely as cleaning fluid in well work and chemical process. Low pH.
Arctic pack	A proprietary product, consisting of diesel with some gel additives. Used to prevent freezing of well facilities, which are exposed to cold weather. Becomes a waste as a result of contamination by water, soil, or hydrocarbons, or as a result of a well workover.
Boiler blowdown water	Fresh water used in boilers, typically to make steam for drilling rigs. It is collected when the boiler is taken out of service.
Caustic fluid	A wide range of high-pH materials normally generated by cleaning operations, as off-specification chemical compounds, or as the result of chemical combinations.
Clean-up fluids (washwaters)	Predominantly water which has been contaminated in the process of washing down an area, engine, etc.
Contaminated gravel	Result of spills associated with various oil field operations.
Crude oil	Generated as waste from a well workover or from spills. A blend of many types of hydrocarbons with some impurities. May be contaminated with water and soil.
Diesel	Diesel wastes may be generated as contaminated fuel, solvent, workover fluid, or freeze protection fluid. May be contaminated with small amounts of chemicals or water. All diesel wastes must be carefully evaluated for disposal options - only those classified as non-hazardous or RCRA exempt will be accepted for disposal.
Grey Water (domestic wastewater)	Originally potable water; comes from the kitchen, showers, lavatories, laundry, toilets, and any camp floor drains.
Drill cuttings	Generated when the drill bit penetrates the rock formation. Circulated to the surface with the drilling mud and are mechanically separated from the liquid mud. Can be composed of sand, gravel, clay, shale, hydrocarbon bearing rock, or other naturally occurring formation solids.
Drilling muds, oil-based	Used for cooling and for the flushing of cuttings during well drilling. Typically a mixture of a hydrocarbon fluid (usually mineral oil or diesel), clay or asphalt, some water, and dissolved chemicals, which enhance certain properties of the mud. The odor is characterized by the hydrocarbon fluid. Returned mud may carry a significant amount of solids (soil and rock fragments).
Drilling muds, water-based	Used for cooling, lubricating the drill bit, and flushing cuttings to the surface. Also used to suspend solids during the grinding and injection disposal process. Consist of water, clay (usually bentonite), and additives such as barium compounds that enhance certain properties. Returned mud may carry a significant amount of solids (soil and rock fragments).

Waste	General Description ***Note:*** *Wastes on this list* ***are not*** *automatically approved for injection. Each must be evaluated for disposal in accordance with Section 2 of the Waste Analysis Plan*.
Frac sand	Certain well stimulations utilize proppant or "frac sand" to fill formation fracture spaces created during a well stimulation. An inert ceramic material, and as a waste it is commonly accompanied by crude oil, fresh or sea water, formation solids, small amounts of chemicals and spent acid. Frac sand waste may be found at the wellhead, in production facility separation vessels, and in flow line pigging material.
Glycol	An alcohol that is widely used in circulating fluid systems to prevent freezing. May be contaminated with water, hydrocarbons, or solids.
Incinerator ash	The result of burning paper, wood products, rags, etc. in an incinerator. It can be injected as slurry if testing confirms it is non-hazardous.
Laboratory waste	Various chemicals, products, and contaminants, some of which will be regulated as hazardous waste.
Line Pigging Material	Materials that have built up on the walls of crude oil pipelines and produced water or seawater pipelines. Normally pushed through the pipelines back to the production facilities and deposited in facility vessels, from which it is later removed as vessel sludge/sand. Occasionally pigging waste will be removed directly from pipelines. Can include crude, produced or seawater, biomass, paraffin, formation solids, frac sand, calcium scale, and iron sulfide.
Lubricating oils and hydraulic fluids	Produced as wastes from engines and power transmission systems. Contain small amounts of metal and chemical additives to enhance their properties.
Methanol	Light alcohol used widely as a freeze prevention fluid. May be used in combination with other materials, such as glycol.
Miscellaneous wastes	Includes seawater, surface runoff to well cellars, snowmelt, and fresh water, which is not considered clean-up fluid. May contain small amounts of contaminants.
Natural gas liquids (NGLs)	Petroleum products (propane, butane, etc.) which are disposed of as wastes when they become contaminated with water, solids or some other hydrocarbon. Ignitable.
Naturally occurring radioactive material (NORM)	Weakly radioactive natural material that sometimes forms as pipe scale or sludge in production pipelines, tubing, and separation vessels. The material is typically found as barium sulfate scale with some radium 226 or 228 co-precipitating with barium. Radiation levels of 1 to 2 millirems per hour are below activity levels of concern by the Nuclear Regulatory Commission.
Produced water	Brine produced from the oil reservoir during the oil recovery process, separated from the oil and gas.
Produced solids	Solids produced from oil reservoir during the oil recovery process and may include solids from well flowbacks prior to production.
Production chemicals	Broad category that includes chemicals used in production or transportation of crude to achieve certain desirable effects. Examples include corrosion inhibitors, emulsion breakers, foam suppressants, and proprietary compounds used in drilling fluids, muds, and cleaning products.
Production facility fluids	Broad category that includes chemicals not used to treat or process produced fluids. Examples include fire water, H2S or oxygen scavenger, MEG, non-process water from various sources, and chemicals from bulk storage
Solvents	A wide range of products that may be contaminated with grease, solids, and/or water. All solvents must be carefully evaluated for disposal options - only those classified as non-hazardous will be accepted for disposal.
Source water	(Not planned for use at Alpine at this time.) Subsurface water produced from saline aquifers below the permafrost. Potentially used for making drilling mud and flushing the disposal well.

Waste	**General Description** ***Note:*** *Wastes on this list* ***are not*** *automatically approved for injection. Each must be evaluated for disposal in accordance with Section 2 of the Waste Analysis Plan*.
Stimulation fluids	Chemical compounds which are injected into producing or injector zones to enhance the productivity or injectivity of a well. May contain various chemicals to enhance its properties.
Transformer oil (no PCBs)	Used as a non-conducting medium in electrical power transformers. Discarded when the equipment is abandoned.
Vessel sludge/sand	Fine solid particles from the oil producing formation, biomass, pipe scale, or frac sand. Can accumulate in test separators, tanks, production facility vessels, and heat exchangers. These solids are periodically removed and can be associated with crude oil, fresh or seawater, and production chemicals or solvents.
Workover fluids	Wastes from the maintenance of a hydrocarbon production well. Predominantly water; may contain small amounts of chemicals, crude oil and solids.

EXHIBIT 3
TYPICAL ALPINE WASTE STREAMS

RCRA-Exempt Waste Streams	**Typical Exempt Sources**	**Main Constituents**	**Potentially Hazardous Properties or Constituents**
Exploration & Production (E&P)	• Primary drilling and production operations • Drilling rigs, well cellars, production lines & vessels	Hydrocarbons, formation solids, returned drilling mud, used freeze-protection fluids	Note that exempt wastes are not regulated as hazardous waste but they may require special handling due to flash point, corrosivity, or other properties.
Non-Exempt Waste Streams	**Typical Non-Exempt[1] Sources**	**Main Constituents**	**Potentially Hazardous Properties or Constituents**
Boiler blowdown	• Rig or production facility boilers	Water	Typically non-hazardous; possibility of heavy metals
Contained snow / ponded water	• Outdoor containment around fuel and chemical storage tanks • Depressions on or between pads & roads	Water, possible traces of hydrocarbon or chemicals if there have been spills	Typically non-hazardous
Diesel Exhaust Fluid	• Vehicles	Water and Urea	Typically non-hazardous
Glycol / heat exchange media	• Chemical storage tanks • Vehicles & equipment (antifreeze)	Glycol (MEG, DEG, TEG, propylene)	Typically non-hazardous
Hydrotest fluid (water or glycol only)	• Pressure test new or non-exempt process lines, vessels • **Non-exempt methanol or diesel must be recovered for re-use, not disposal**	Water, glycol, possible product residual in existing lines, traces of chlorine or other biocide	Typically non-hazardous unless methanol or diesel are used
Incinerator ash or sludge	• Trash and camp waste • Sewage sludge	Particulates	Typically non-hazardous; possibility of heavy metals
Lubrication oil	• Motor oil • Transmission fluid • Hydraulic oils	Hydrocarbon	Typically non-hazardous; possible flash point or organic chlorides from solvent or fuel contamination
Non-exempt drilling, well work materials	• Drilling mud and additives that have not been circulated downhole • Gel, barite, calcium carbonate, polymers, lost circulation material (LCM) • Cement or grout/cement or grout) rinsates • Fresh or seawater rinsate with product residual	Varies	Typically non-hazardous; cement /grout rinsates, acids and caustics must be non-hazardous for pH (spot check and neutralize as needed). Non-exempt methanol or diesel not approved for disposal
Non-exempt rinsate/ wash water	• Internal or external washdown of skids, modules • Equipment cleaning (using non-hazardous detergents or degreasers)	Water, possible traces of hydrocarbon, chemicals, detergent	Typically non-hazardous; possibility of benzene or flash point (from hydrocarbons)
Non-exempt spill clean-up	• Fluids recovered from cleanup of non-exempt spills • Contaminated gravel or snow	Water, snow, gravel, with hydrocarbon or chemical products	Depends on product spilled – may contain benzene (diesel or gasoline spills), flash point, listed constituents
Off spec product	• Products spilled, out-dated or no longer acceptable for original purpose	Varies	Varies - check for listed wastes, solvents, heavy metals
Parts Washer Fluid	• Equipment shops	Water, grease, oil, soap	Typically, non-hazardous, possibility of benzene or other metals
Photo processor fluid	• Spent developer solution from x-ray equipment (corrosion tests, medical), after passing through silver recovery unit	Water	Typically non-hazardous after silver removed and recovered
Scale Inhibitor	• Rinse loads from tank steaming	Water, glycol, phosphonate salt	Typically non-hazardous; possibility of metals
Sewage / sludge	• Camp wastewater treatment plant(s) and site enviro-vacs	Water, soap residuals, human waste	Typically non-hazardous
Soap	• Cleaning out tanks, etc.	Water, hydrocarbons	Non-hazardous
Sump fluids/ Sump solids	• Snowmelt and external dirt from vehicles and equipment, collected in floor drains • Floor washings • Incidental equipment leaks & spills	Water, grit, possible traces of hydrocarbon **Process control is critical - hazardous wastes should never be dumped or drained to floor sumps**	Typically non-hazardous, but may occasionally contain spill residue that must be evaluated

Turbine wash water	• Routine cleaning of turbine fins	Water, detergent, sometimes methanol	Possible flash point (if methanol used), cadmium or other metals
Other	• Any waste not covered by another waste stream	Varies	Varies

1. Note that similar wastes may be RCRA exempt, depending on waste-generating process.

EXHIBIT 4
ANALYTICAL REQUIREMENTS FOR NON-EXEMPT WASTE STREAMS

Parameter **(See Exhibit 5 for Methods)**	**Initial Testing Requirement**	**Fingerprint**[1]	**Acceptable Range**
Appearance		**X**	Descriptive only – no pass/fail criteria. Fingerprint similar to initial characterization result
pH (aqueous fluids)	**X**	**X**	2<pH<12.5 Fingerprint similar to initial characterization result
Flash point (liquids)	**X**	**X**	>60°C (>140°F) Fingerprint similar to initial characterization result
Reactivity	**X**		Nonreactive – descriptive pass/fail criteria using generator knowledge of 40 CFR 261.23 properties[2]
TCLP Metals	**X**	**X**	See Exhibit 7
TCLP Volatiles	**X**		See Exhibit 7
TCLP Semi-Volatiles	**X**		See Exhibit 7
Benzene and/or a more diagnostic TCLP constituent[3] , Total or TCLP[4] (mg/l)		**X**	< 0.5 mg/L (liquid) or 10 mg/kg (total concentration for solids) Fingerprint similar to initial characterization result

This database is currently accessible on the CPAI Intranet Site.

s annually

2 EPA's Methods Innovation Rule (70 FR 34538, 6/14/05) withdrew various reactivity test methods from SW-846. Instead, generators must use other appropriate methods or process knowledge in determining whether a particular waste is hazardous due to its reactivity.

3 Fingerprint results are compared to the initial characterization result to determine that the waste is similar and remains non-hazardous. When a constituent other than benzene is more diagnostic of potential changes to the stream it should be selected for fingerprinting (e.g., silver in spent photo processing effluent following silver recovery).

4 Any solid sample that exceeds 10 mg/kg total benzene (20 times the TCLP limit of 0.5 mg/L) must be re-analyzed by TCLP method.

EXHIBIT 5
ANALYTICAL METHODS [1]

Analysis and Method recommended	Recommended Container	Preservative	Holding Time	Acceptable Range for Non-Hazardous Material
Ignitability (flash point) SW-846, 1010 (Pensky-Martens) SW-846, 1020 (Setaflash)	40 mL, VOA,	Chill to 4°C	7 Days	Flash point > 140°F (60°C)
Corrosivity (pH) - Liquid SW-846, EPA 9040B, EPA 1110	125 ml polyethylene/glass	Chill to 4°C	As soon as possible[2]	2 < pH< 12.5
Reactivity Evaluation of 40 CFR 261.23 narrative properties				Nonreactive
Toxicity Characteristics Leaching Procedure (TCLP) Extraction SW-846, 1311*	See below	See below	See below	See Exhibit 7
TCLP Metals (SW-846) Arsenic .... SW-846, 6020 Barium .... SW-846, 6020 7080A/7081 Cadmium ...... SW-846, Lead .... SW-846, 6020 Mercury......... SW-846, 7470A/7471A Selenium ...... SW-846, 6020 Silver .... SW-846, 6020 Chromium SW-846, 6020	1L amber glass, Teflon-lined cap	Chill to 4°C	Extract w/in180 days except mercury (28 days)	See Exhibit 7
TCLP Volatile Organics, SW-846, 8240A/8260 Benzene only (liquid)[3]: SW-846, 8260	1L amber glass, Teflon-lined cap For benzene, 40 ml VOA vial (liquids), no headspace,	Chill to 4°C	14 days	See Exhibit 7 Benzene <0.5 mg/L
TCLP Semi-volatile Organics SW-846, 8270C	1L amber glass, Teflon-lined cap	Chill to 4°C	Extract w/in 14 days	See Exhibit 7
Appearance (color, homogeneity, etc.) Visual observation against clear or white background	Clear container		As soon as possible	

1 Alternate EPA-approved test methods may be substituted per EPA's Methods Innovation Rule (70 FR 34538, 6/14/05) except as noted* Appendix III to part 261—Chemical analysis test methods prescribed by the UIC permits has been removed from 40 CFR Part 261.

2 In the field, pH should be measured as soon as the sample is collected. For samples analyzed by a commercial laboratory, the holding time is 24 hours following collection.

3 Total concentration evaluations are appropriate for liquids that do not require TCLP extraction, or as a screening method for solids (20x rule), or as an alternative demonstration of a low concentration when the corresponding TCLP value has a high reporting level due to interferences or laboratory-required sample dilutions. A total concentration provides worst-case scenario. Any solid sample total concentration that exceeds 20x a TCLP threshold must be re-analyzed by TCLP or will be presumed to be hazardous waste

EXHIBIT 6
HAZARDOUS WASTE CHARACTERISTICS

Ignitability	• Alcohol content of greater than 24 percent, and/or • Flash point less than 140 degrees Fahrenheit (60 degrees Centigrade)
Corrosivity	• pH less than or equal to 2 or greater than or equal to 12.5, or • Corrodes steel (SAE 1020) at a rate greater than 6.35 mm (0.250 inch) per year at a test temperature of 55°C (130°F)

Reactivity	• No test methods can identify chemical concentrations indicative of a reactive hazardous waste:
	• Narrative criteria include:
	  • Normally unstable and readily undergoes violent change without detonating
	  • Reacts violently with water
	  • Forms potentially explosive mixtures with water
	  • When mixed with water, generates toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment
	  • Is a cyanide or sulfide bearing waste which, when exposed to pH conditions between 2 and 12.5 can generate toxic gases;
	  • Is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement
	  • Is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure; or
	  • Is a forbidden explosive as defined in 49 CFR 163.51, a Class A explosive as defined in 49 CFR 163.53, or a Class B explosive as defined in 49 CFR 163.88.

Toxicity	• Contains any of the contaminants listed on Exhibit 7 above the indicated concentration

EXHIBIT 7
HAZARDOUS WASTE TOXICITY CHARACTERISTICS

As determined by Toxicity Characteristics Leaching Procedure (TCLP)
Source: 40 CFR 261.24

Contaminant	Maximum concentration (mg/L)	Contaminant	Maximum concentration (mg/L)
TCLP Metals		**TCLP Semi-Volatiles**	
Arsenic	5.0	o-Cresol	200.0*
Barium	100.0	m, p-Cresol	200.0*
Cadmium	1.0	m, p-Cresol	200.0*
Chromium	5.0	Cresol (total)	200.0*
Lead	5.0	2,4-Dinitrotoluene	0.13**
Mercury	0.2	Hexachlorobenzene	0.13**
Selenium	1.0	Hexachlorobutadiene	0.5
Silver	5.0	Hexachloroethane	3.0
		Nitrobenzene	2.0
TCLP Volatiles		Pentachlorophenol	100.0
Benzene	0.5	Pyridine	5.0**
Carbon tetrachloride	0.5	2,4,5-Trichlorophenol	400.0
Chlorobenzene	100.0	2,4,6-Trichlorophenol	2.0
Chloroform	6.0		
1,4-Dichlorobenzene	7.5	**TCLP Pesticides/Herbicides*** **	
1,2-Dichloroethane	0.5	Chlordane	0.03
1,1-Dichloroethylene	0.7	2,4-D	10.0
Methyl ethyl ketone	200.0	Endrin	0.02
Tetrachloroethylene	0.7	Heptachlor	0.008
Trichloroethylene	0.5	Lindane	0.4
Vinyl chloride*	0.2	Methoxychlor	10.0
		Toxaphene	0.5
		2,4,5-TP (Silvex)	1.0

* If o-, m-, and p-cresol concentrations cannot be differentiated, the total cresol concentration is used.

** Method quantitation limit is higher than regulatory limit. Use quantitation limit as maximum allowable level.

*** Pesticides and herbicides are not used or expected to be present at Alpine. No testing is required.

EXHIBIT 8
NORTH SLOPE MANIFEST FORM

NORTH SLOPE MANIFEST

1. GENERATOR INFORMATION	Field/ Asset ☐ GPB ☐ Deadhorse ☐ Alpine ☐ KRU ☐ Other	Owner Company	Date
		Source/ Well No.	Time ☐ AM ☐ PM
Name (Print)	Rig/ Facility	Cost Code/Activity Code AFE/Approver ID	
Contact Number	☐ Phone ☐ Pager ☐ Radio ☐ Harmony		

2. GENERATING ACTIVITY OR PROCESS	3. VOLUME (Estimate) ☐ bbl ☐ gal ☐ yd^3

4. DESCRIPTION (Composition must equal 100% - use whole numbers)

Crude Oil	%	Glycol	%	Fresh Water	%
Produced Water	%	Acid	%	Seawater/Brine/KCl	%
Drilling Mud	%	Frac Sand	%	Source Water	%
Cuttings	%	Diesel/Water Gel	%	Reserve/Flare/Relief Pit Water	%
Cement/Rinsate	%	Scale/Corrosion Inhibitor	%	Snow	%
Diesel	%	Boiler Blowdown	%	Gravel/Sand	%
Methanol	%	Used Oil	%	Domestic Wastewater	%

OTHER: Describe & check applicable box		Approved by: (Name/Date)		Listed in *Red Book*
1.	%	☐	OR	☐
2.	%	☐		☐

5. REUSE / RECYCLE / EOR: Will the material be reused/recycled as approved in the *Red Book*?

☐ **YES** Select method at right and go to PART 8 — ☐ Water recycle/EOR — ☐ Other beneficial reuse (Describe):

☐ **NO** Go to PART 6 — ☐ Hydrocarbon recycle

6. CLASS II DISPOSAL: Was the waste brought to the surface or otherwise approved for Class II disposal?

☐ **YES** Go to PART 7 if Class I facility will be used **OR** Part 8 if Class II facility will be used

☐ **NO** Go to PART 7 or contact Environmental

7. CLASS I DISPOSAL: Is the waste either non-hazardous or exempt from regulation as hazardous waste (40 CFR 261.4)? Refer to the Red Book and other appropriate guidance.

☐ **YES** Select classification at right and go to PART 8.	☐ Non-exempt, Non-hazardous	**Comments**
☐ **NO** Contact Environmental - no Class I disposal	☐ RCRA-exempt	

8. DESTINATION (Name of Facility)

Alpine	☐ A1 Recycle	☐ CD1-01a	☐ CD1-19	☐ WD02/L2	☐ HWCAA
Kuparuk	☐ CPF-1 Hydrocarbon Recycle	☐ CPF-1 Water Recycle	☐ CPF-1 Oily Waste Storage Cell		
	☐ 1R-18 Class II Well ☐ DS-1B Class II Well	☐ C/D Warehouse	☐ 1-H Oily Waste Storage Cell		
Greater Prudhoe Bay	☐ Pad 3 Waste Facility	☐ Grind & Inject Facility	☐ FS1	☐ GC2	
OTHER (Include Field and Location)					

9. TEST DATA (If required by receiving facility)	☐ Attached	pH	Water %	Org. chlorides	ppm
	☐ On file	Flash pt. °F	Solids %	Hydrocarbons	%

10. GENERATOR	Name (Print)	Signature	Date
Certification	*This consignment, to the best of my knowledge and belief, is accurately described above and I have applied the provisions of the Alaska Waste Disposal and Reuse Guide in making decisions concerning the reuse or disposal of this material.*		
11. TRANSPORTER 1	Name (Print)	Signature	Date
Company:		Truck/Trailer No:	
TRANSPORTER 2	Name (Print)	Signature	Date
Company:		Truck/Trailer No:	
12. RECEIVER	Name (Print)	Signature	Date
Accepted ☐ Rejected ☐	Redirected ☐	Reason/Comments:	
Offloaded at:		Volume	☐ bbl ☐ gal ☐ yd^3

COMMENTS: If this is a mixed load, cross-reference other manifest numbers here:

Form Revised May **2015** (previous versions revised February 2013 may be used)
COPIES – Follow site-specific filing instructions

ORIGINAL – Receiving Facility

Appendix B

Simulation of Slurry Injection:
Alpine Field – CD1-19A

Prepared for:

ConocoPhillips Alaska - Alpine
1800 E. 1st. Avenue
Anchorage, Alaska 99501

Prepared by:

ASRC Energy Services
E&P Technology, Inc.

August 2007

TABLE OF CONTENTS

I. BACKGROUND

ConocoPhillips Alaska is considering injecting slurry into a dedicated disposal well in the Alpine development. Hydraulic fracturing simulations were carried out using commercial and proven software (MFrac™) to assess the evolution of fractures associated with injection into this well. The target well is CD1-19A and the injection will be into the Ivishak formation.

II. MATRIX OF SIMULATIONS

Appendix A summarizes the input material properties. The variables adopted in the simulations are described below

II.1 Various Completion Schemes:

Perforations or possible perforations) are shown in Table 1.

Table 1. Perforated Intervals

Vertical Depth of Perforations (feet TVD)	Measured Depth of Perforations (feet MD RKB)	Comments
8551-8605	10877.6-10933.9	Sag River
9116-9138	11462.8-11485.5	Ivishak
9156-9173	11504.1-11521.6	Ivishak
9366-9385	11720.5-11740.1	Ivishak
9394-9407	11749.3-11762.7	Ivishak
9412-9420	11767.9-11776.1	Ivishak
9424-9437	11780.2-11793.6	Ivishak
9443-9456	11799.7-11813.1	Ivishak

The situations considered were as follows.

1. All Ivishak perforations.
2. Lower five sets of Ivishak perforations
3. Upper two sets of Ivishak perforations
4. All perforations.
5. Sag River perforations only.

II.2 Fluids:

The fluids used were neat produced water or seawater (no solids) at an estimated temperature of 70°F (at the sandface) [spearhead and flush], a 9.6 ppg slurry [equivalent to a base fluid with approximately 1.5 ppa (pounds of proppant - solids - added)], and a 10.1 ppa slurry [equivalent to a base seawater fluid with approximately 2.4 ppa solids]. Power law rheologies for these fluids were specified and these are shown in Table 2.

Table 2. Fluid Rheology

Fluid	n'	K' ($lbf\text{-}s^{n'}/ft^2$)	Weight (ppg)	Specific Gravity
Seawater/PW (base fluid)	1.0	1.313×10^{-5}	8.66	1.04
9.5 ppg slurry	0.7	1.022×10^{-3}	9.5	1.14
10.1 ppg slurry	0.7	7.156×10^{-3}	10.1	1.21

II.3 Injection Schedules:

Several schedules were adopted for assessing slurry injection. Various parametric simulations were run and key results are reported for the following scenarios.

1. 1000 bbl of 9.6 ppg slurry with a spearhead and flush injected at 2.5 BPM
2. 1000 bbl 9.6 ppg with a spearhead and flush at 3.5 BPM.
3. 2500 bbl of 9.6 ppg slurry with a spearhead and flush injected at 2.5 BPM
4. 2500 bbl of 9.6 ppg slurry with a spearhead and flush at 3.5 BPM.

These were repeated with a 10.1 ppg slurry. Certain additional parametric runs were carried out to look at variations in the predicted input parameters.

III. RESULTS

Results of the fracturing simulations are summarized in Table 3. Figures for the various cases are provided in Appendix B. As can be seen, the parametric evaluations included the zones open to injection, the fluids, rates and volumes. A case was also run where the permeability and the fluid loss coefficient were reduced by one-half – with no significant difference in the forecasted geometries.

Table 3. Summary of Fracture Dimensions at the End of Injection

Case	Completion	Rate (BPM)	Injection Fluid	Total Volume[1] (bbl)	Fracture Half-Length[2] (ft)	Maximum Wellbore Width (inches)[3]	EOJ[4] Net Pressure (psi)
1	All Ivishak perforations	2.5	9.6 ppg	1,000	504	0.09	365
2	All Ivishak perforations	3.5	9.6 ppg	1,000	535	0.09	383
3	All Ivishak perforations	2.5	9.6 ppg	2,500	739	0.10	391
4	All Ivishak perforations	3.5	9.6 ppg	2,500	790	0.11	390
5	All Ivishak perforations	2.5	10.1 ppg	1,000	365	0.14	381
6	All Ivishak perforations	3.5	10.1 ppg	1,000	371	0.15	373
7	All Ivishak perforations	2.5	10.1 ppg	2,500	431	0.14	319
8	All Ivishak perforations	3.5	10.1 ppg	2,500	462	0.14	315
9	All Ivishak perforations [fluid loss and permeability reduced by one-half]	3.5	10.1 ppg	2,500	721	0.16	305
10	Upper two Ivishak zones	3.5	10.1 ppg	2,500	480	0.15	314
11	Lower five Ivishak zones	3.5	10.1 ppg	2,500	525	0.18	363
12	Sag River only	2.5	9.6 ppg	1,000	528	0.10	251
12	Sag River only	3.5	9.6 ppg	1,000	553	0.11	253

[1] Excluding displacement volumes - spearhead and flush.
[2] Fracture half-length is the length from the wellbore to the tip of one wing of an assumed symmetrical fracture (i.e., the modeling presumes that two identical fracture wings grow diagonally away from the wellbore in the direction of the maximum horizontal principal stress. The length shown is the greatest for any of the zones taking fluid.
[3] Maximum wellbore width is the maximum fracture width at any position along the wellbore – in any zone taking fluid.
[4] After flush, at shut-in.

ConocoPhillips Alaska, Inc.
Injection into CD1-19A

Case	Completion	Rate (BPM)	Injection Fluid	Total Volume[1] (bbl)	Fracture Half-Length[2] (ft)	Maximum Wellbore Width (inches)[3]	EOJ[4] Net Pressure (psi)
14	Sag River only	2.5	9.6 ppg	2,500	727	0.11	245
15	Sag River only	3.5	9.6 ppg	2,500	828	0.12	265
16	Sag River and Ivishak	2.5	9.6 ppg	1,000	362	0.07	328
17	Sag River and Ivishak	3.5	9.6 ppg	1,000	381	0.08	342
18	Sag River and Ivishak	2.5	9.6 ppg	2,500	509	0.08	346
19	Sag River and Ivishak	3.5	9.6 ppg	2,500	557	0.09	366

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Injection into CD1-19A

APPENDIX A

INPUT PARAMETERS

A.1. Well Information:

The wellbore schematic is shown in Figure A-1. The completions considered in CD1-19A are shown in Table A-1.

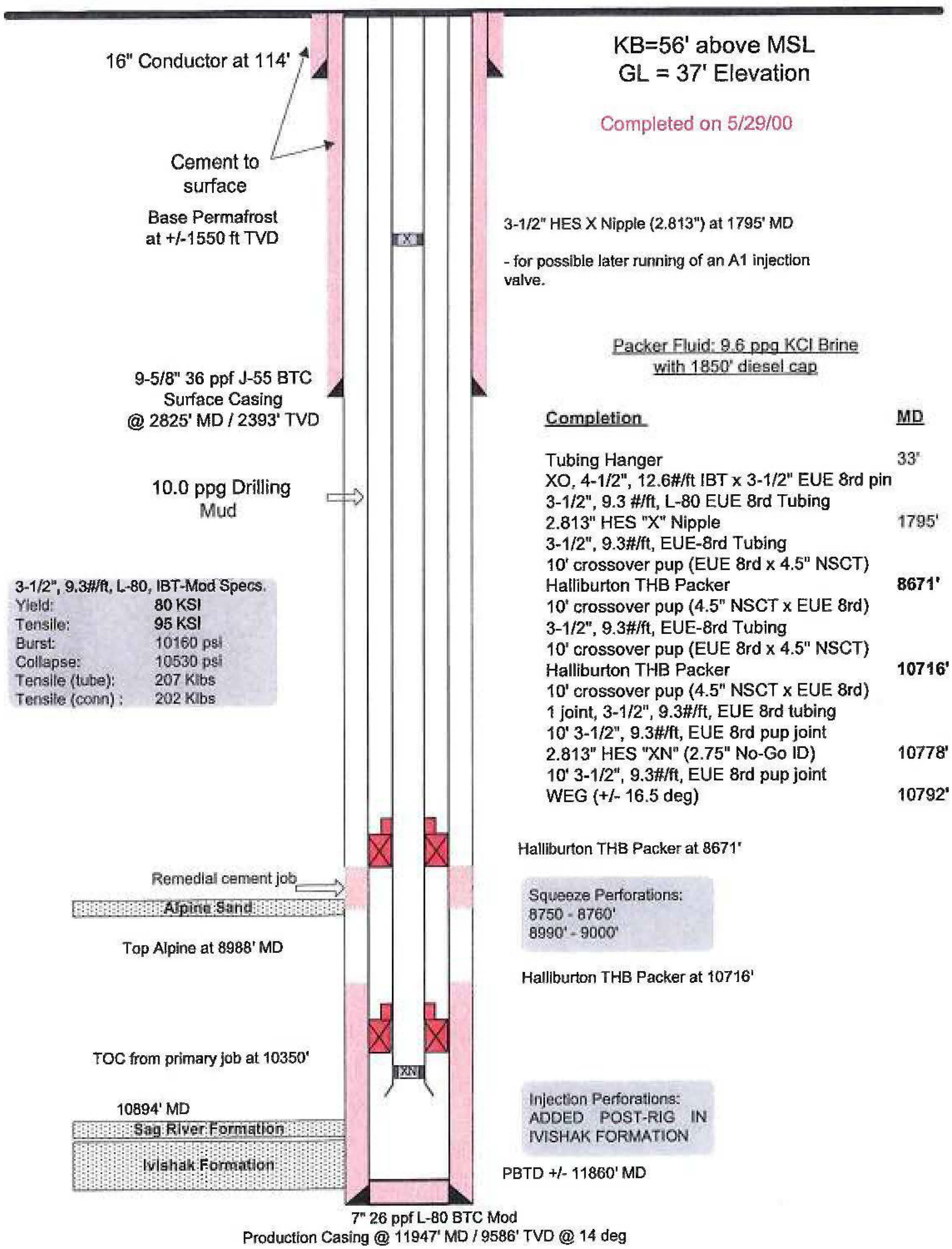

Figure A-1. Wellbore schematic.

Table A-1. Perforated and Openhole Sections

Vertical Depth of Perforations (feet TVD)	Measured Depth of Perforations (feet MD RKB)	Comments
8551-8605	10877.6-10933.9	Sag River
9116-9138	11462.8-11485.5	Ivishak
9156-9173	11504.1-11521.6	Ivishak
9366-9385	11720.5-11740.1	Ivishak
9394-9407	11749.3-11762.7	Ivishak
9412-9420	11767.9-11776.1	Ivishak
9424-9437	11780.2-11793.6	Ivishak
9443-9456	11799.7-11813.1	Ivishak

A.2 Survey Information:

The deviation of the planned injector is shown in Figure A-2.

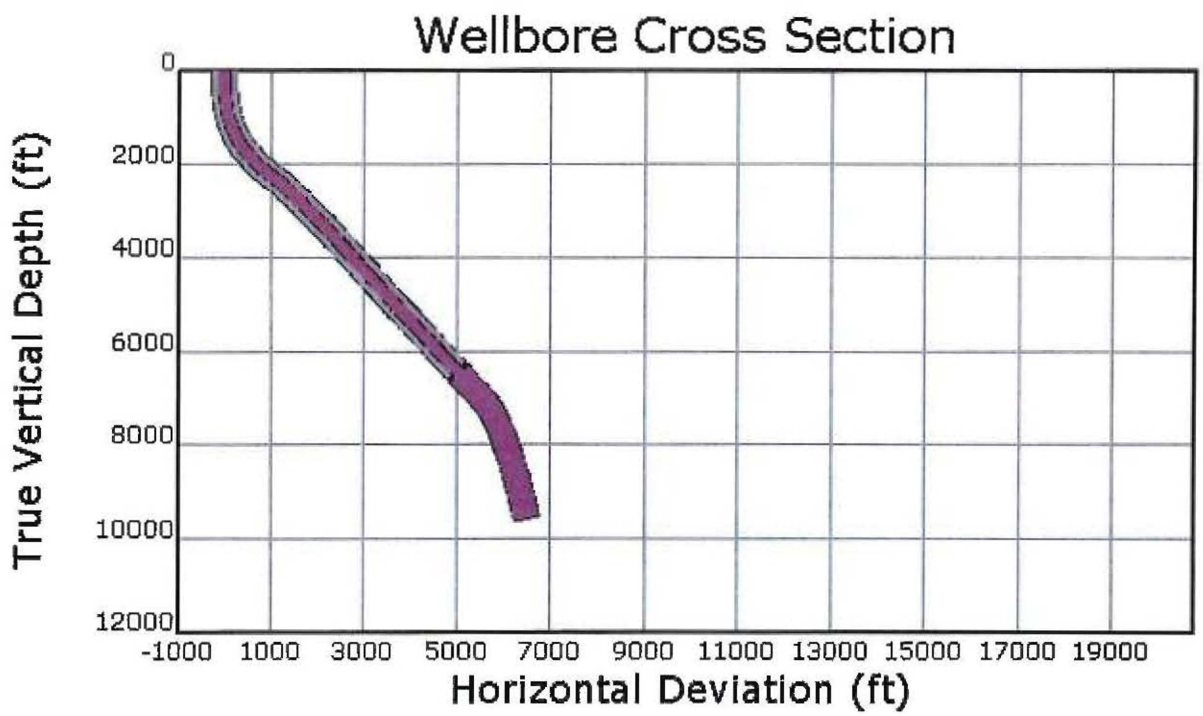

Figure A-2. Wellbore trajectory.

A.3 Stress Information

Figure A-3 shows a type log (Nechelik 1). Injection is planned into perforations in the Ivishak. Perforating in the Sag River was also considered in the simulations. The stress data were generated using synthetic slowness relationships inferred from Well 2F-20. These were calibrated using available injection data and testing previously carried out on the planned injection well.

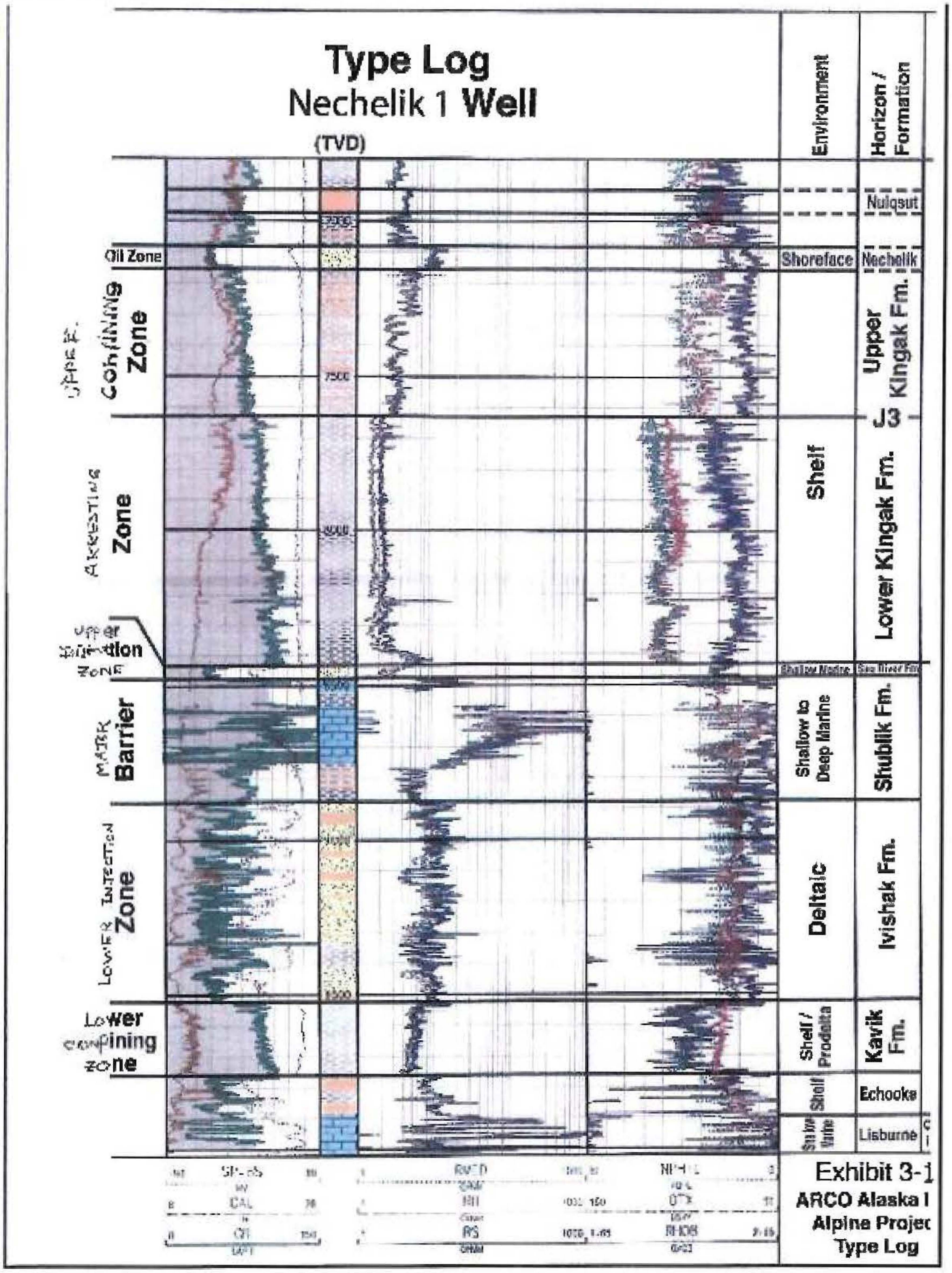

Figure A-3. Typical logging signatures in the Ivishak and overlying and underlying formations.

The inferred stresses are consistent with Ramos et al, 2005.[5] who described geomechanical conditions in the Alpine reservoir itself.

A.4. Fluid Loss Properties

Permeability was estimated using a generic correlation and experience elsewhere with the Ivishak and Sag River formations.

$$k=3.756 \times 10^5 \times (\phi \text{ [decimal]})^{5.064}$$

Figure A-4 shows the inferred permeability variation with depth. Spurt loss (instantaneous loss in fluid when new fracture surface is created) was taken as 10 gallons/100 ft^2. The wall building fluid loss coefficient was estimated as follows (analog situations)

$$C_w = 0.0017\log_{10}k + 0.00008 \text{ ft/minute}^{1/2}$$

Fluid loss coefficients are shown in Figure A-5.

A.5. Mechanical Properties Synthesis

Laboratory values for Young's Modulus were available (Figure A-6). Analog laboratory data were used to calibrate the raw modulus predictions derived from compressional and shear wave slowness (Figure A-7)

A multivariate linear correction using porosity and dynamic modulus was finally selected to correct to static values. This relationship is:

$$E_{static} = -0.15298 + 0.262793\phi - 0.6718E_{dynamic}$$

Poisson's ratio was inferred strictly from the synthetic slownesses (Figure A-8). In-situ stresses were calculated from Poisson's ratio, Young's modulus, formation pressure, and bulk density. AS indicated in Section A-3 calibrations were carried out using available well testing and injection performance data. Stress profiles are shown in Figure A-9.

[5] Ramos, G.G., Erwin, M.D. and Enderlin, M.B.: "Geomechanical Factors in the Successful Implementation of Barefoot Horizontal Completions Totaling 100,000 ft Long, Alpine Reservoir, Alaska," SPE/ISRM 78193, SPE/ISRM Rock Mechanics Conference, Irving, Texas, 20-23 October 2002.

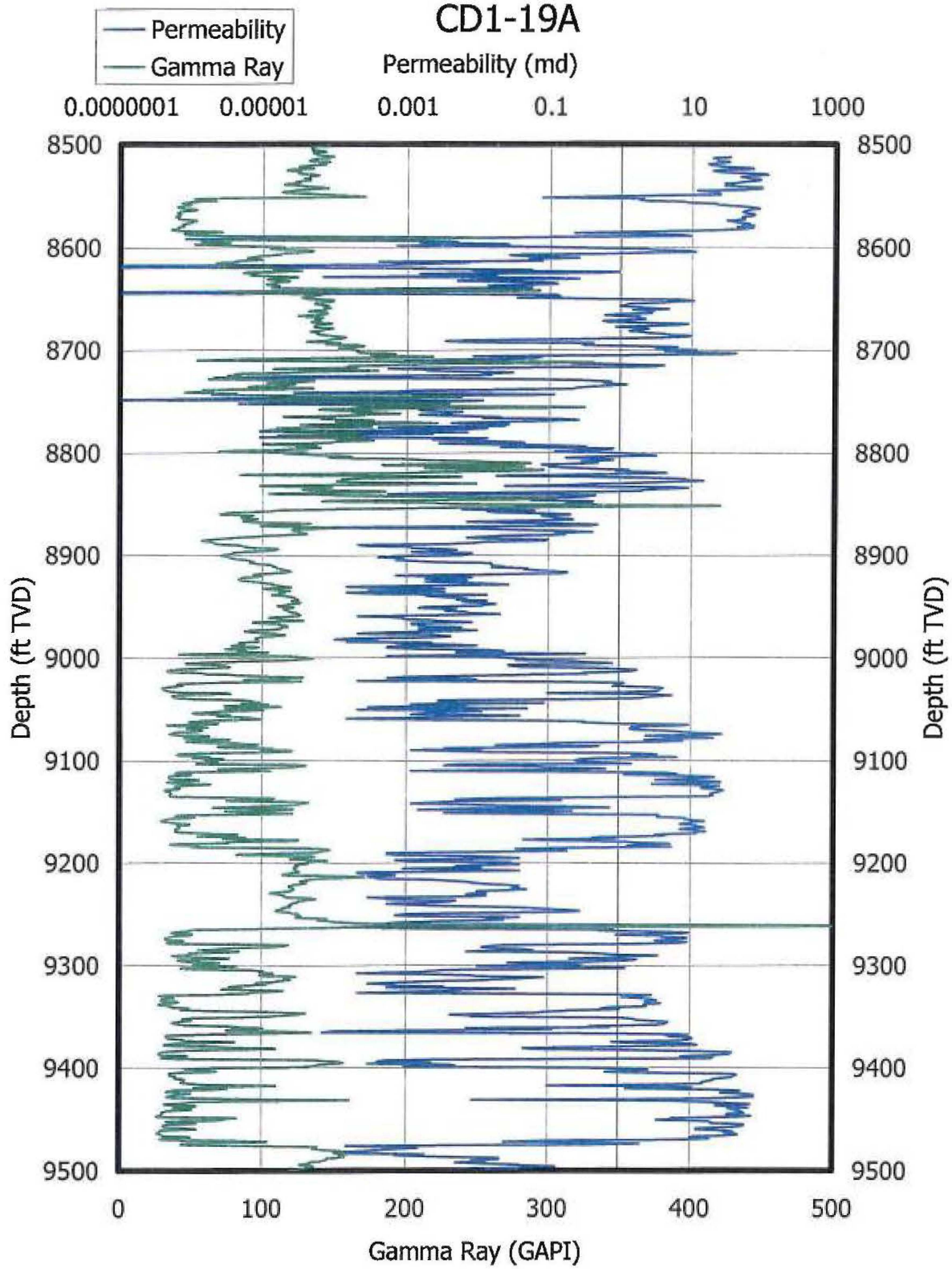

Figure A-4. Estimated variation of permeability with depth.

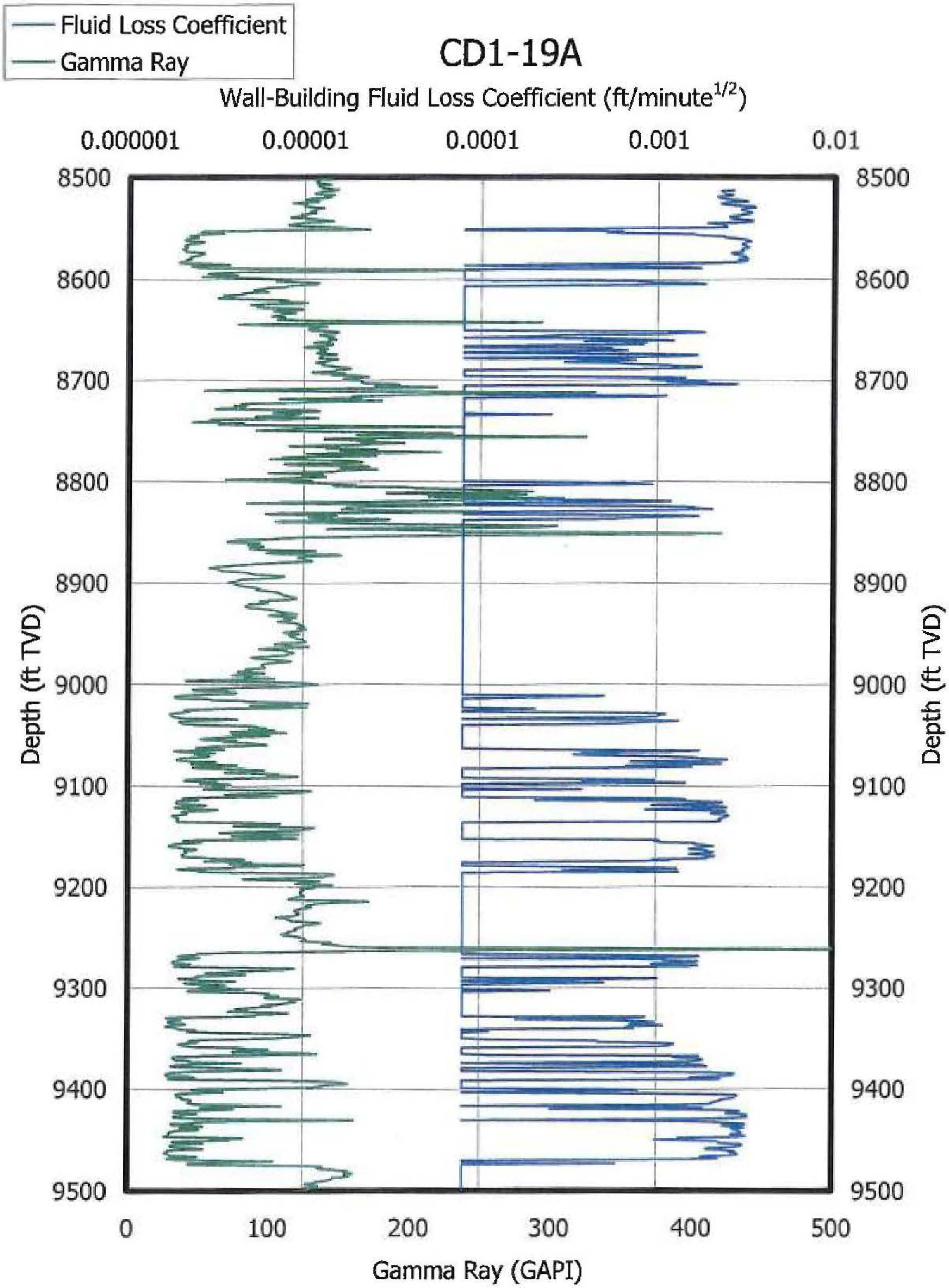

Figure A-5. Estimated variation of wall building fluid loss coefficient with depth.

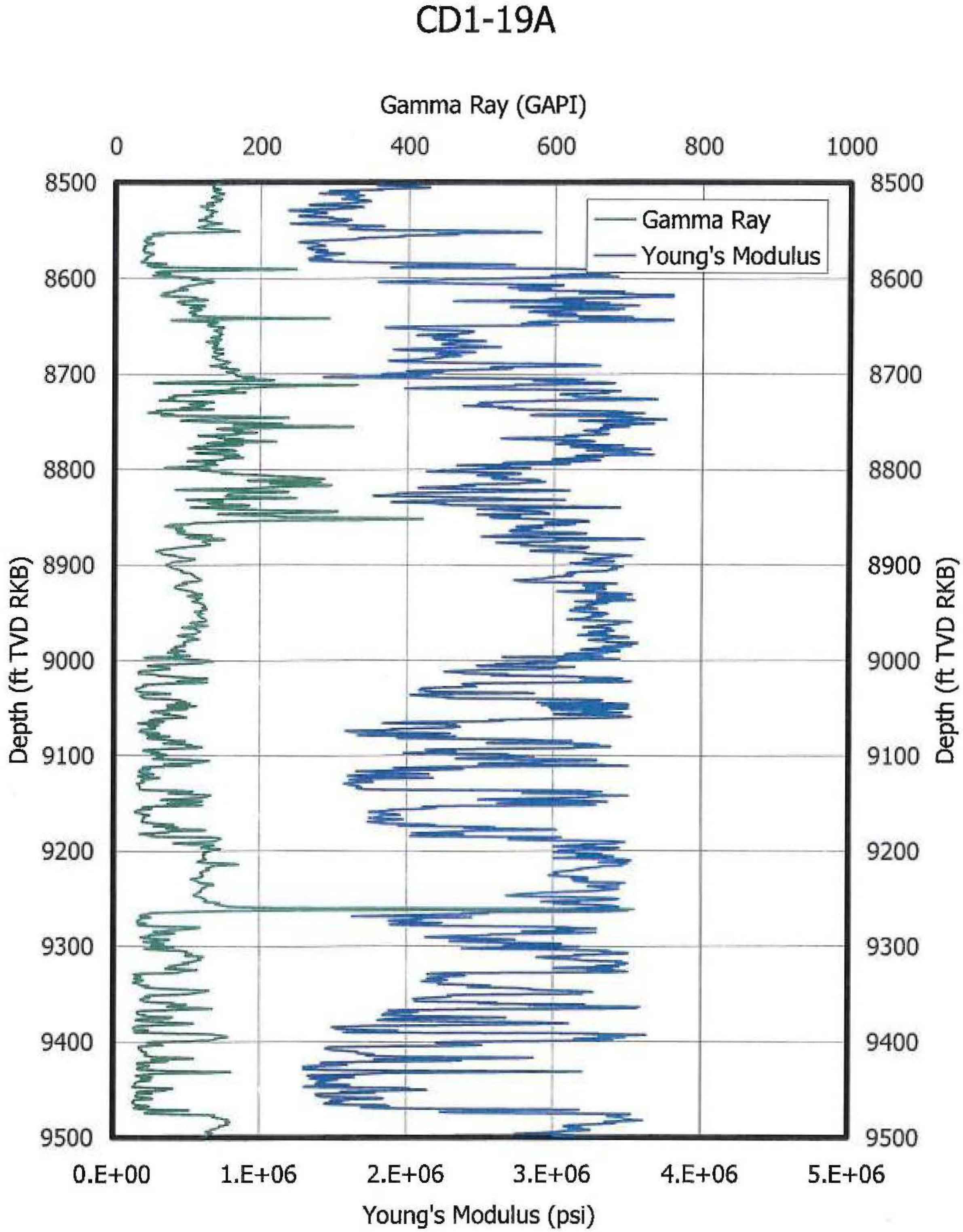

Figure A-6. Estimated static Young's modulus.

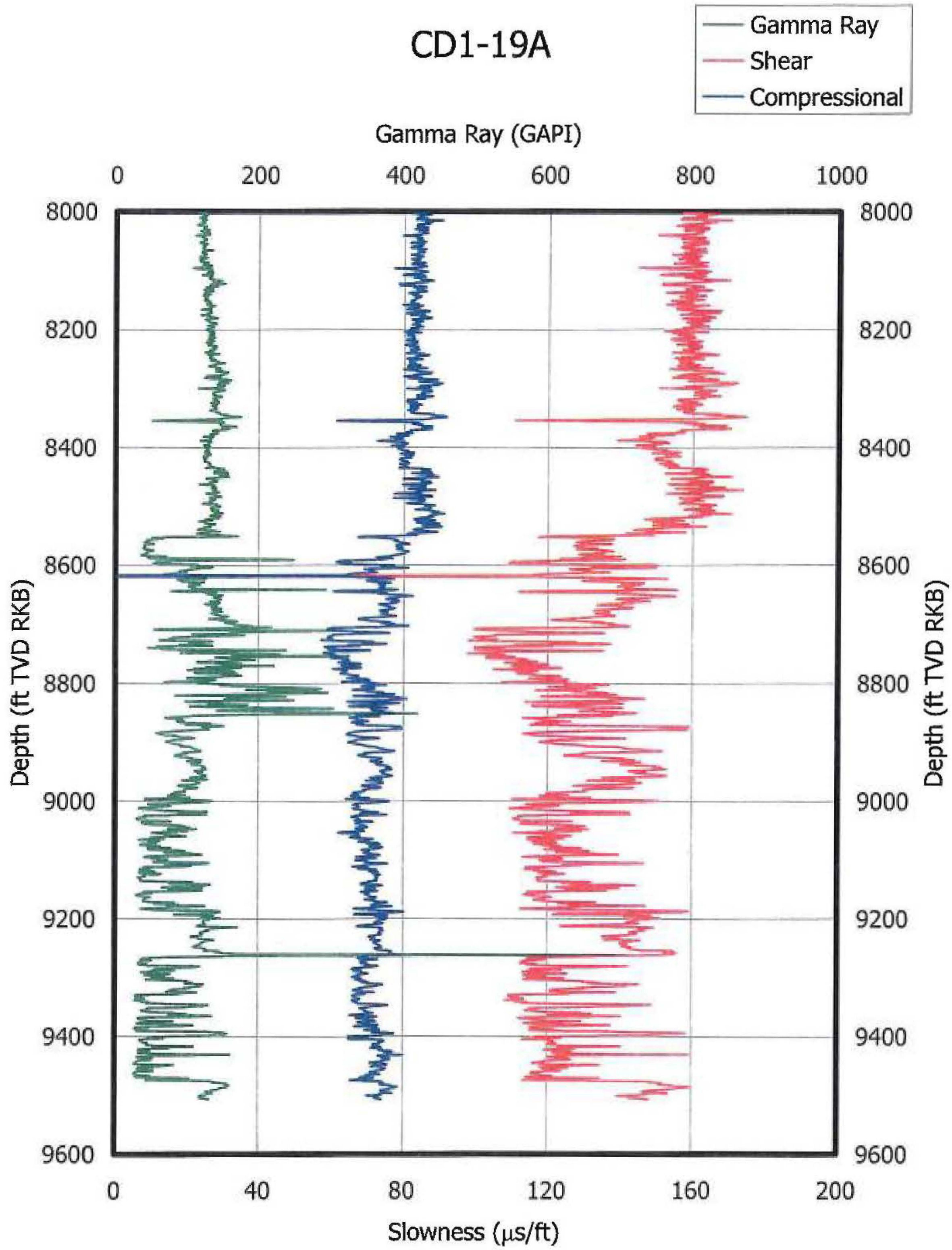

Figure A-7. Compressional and shear wave slowness.

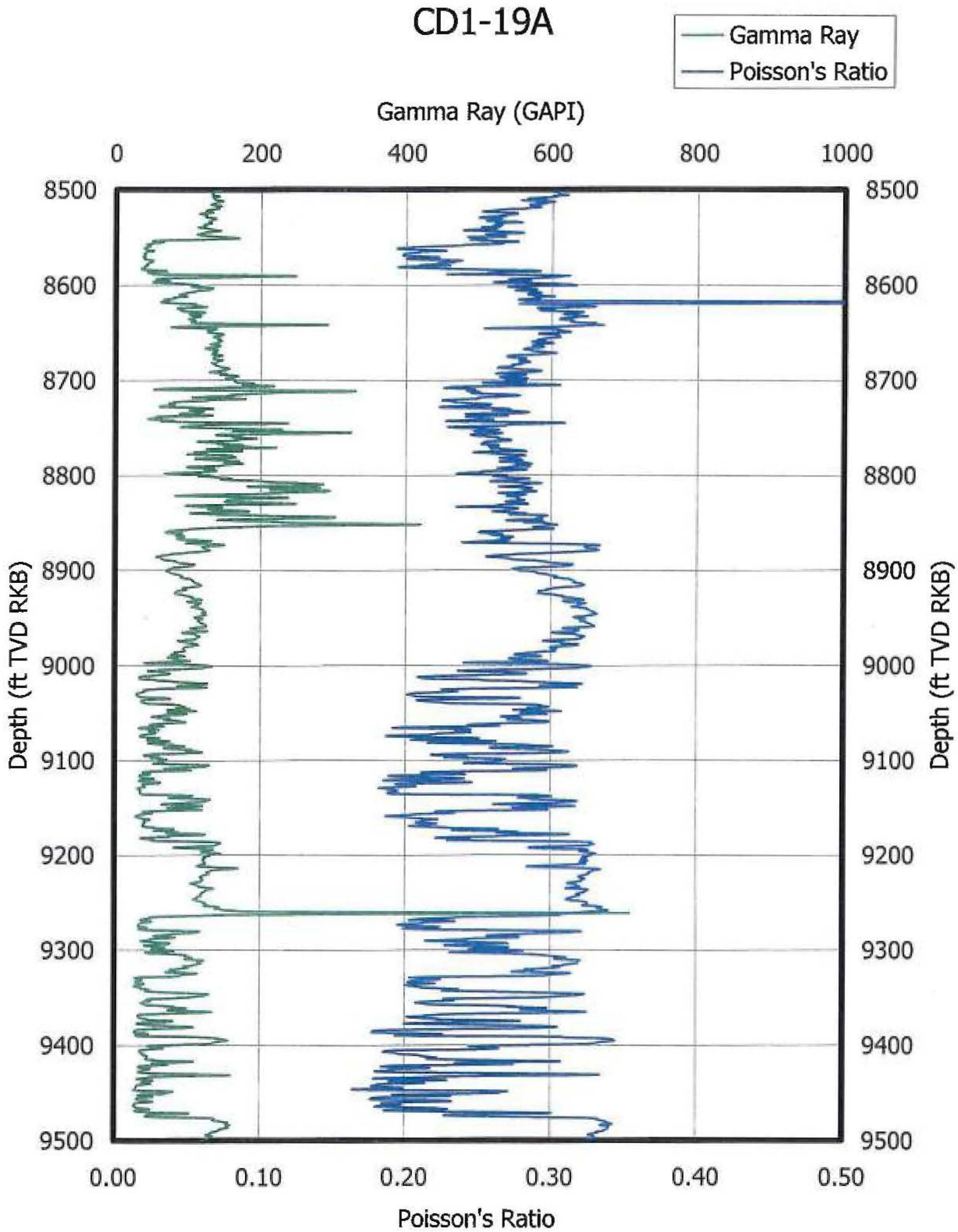

Figure A-8. Estimated Poisson's ratio.

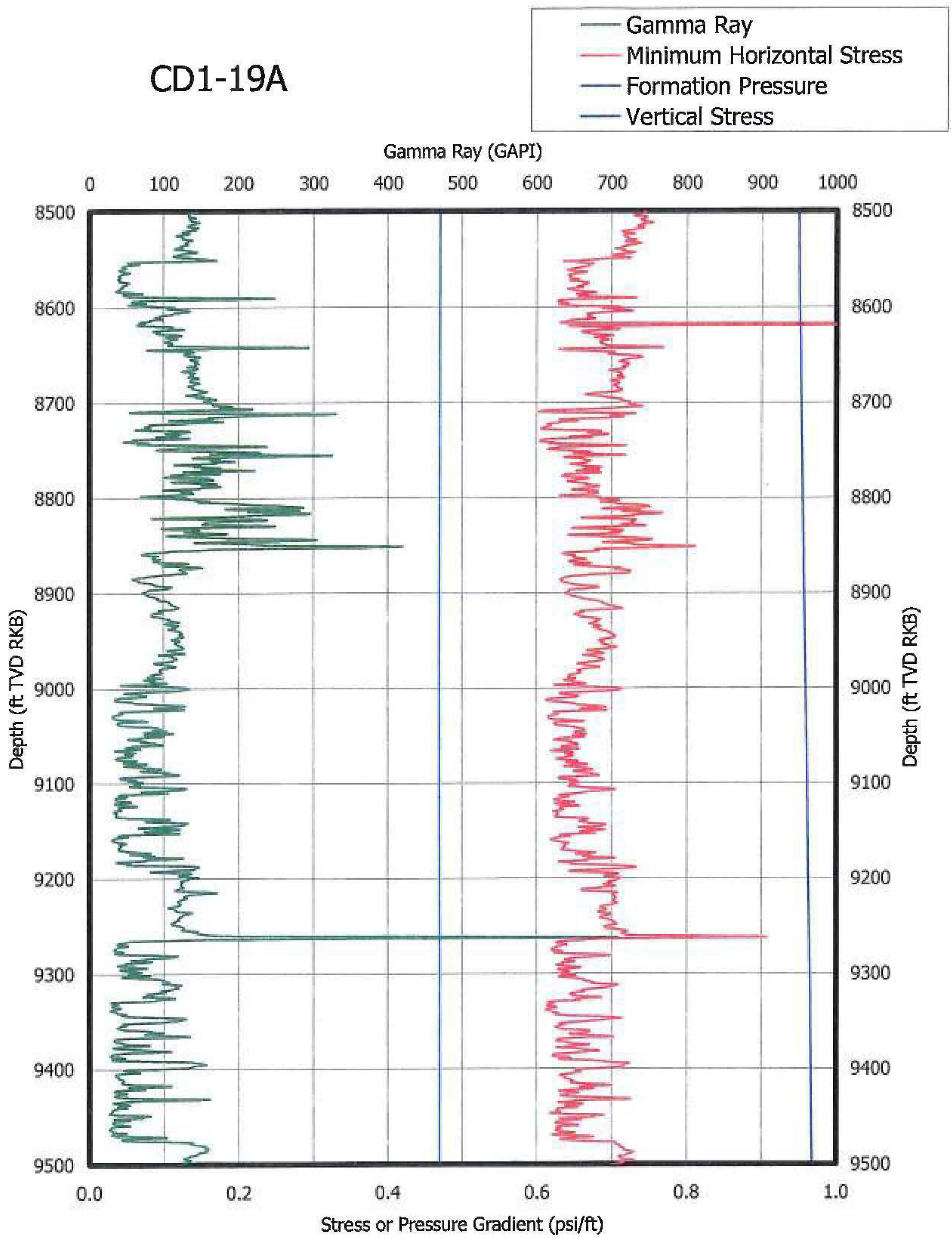

Figure A-9. Stresses and formation pressure gradients.

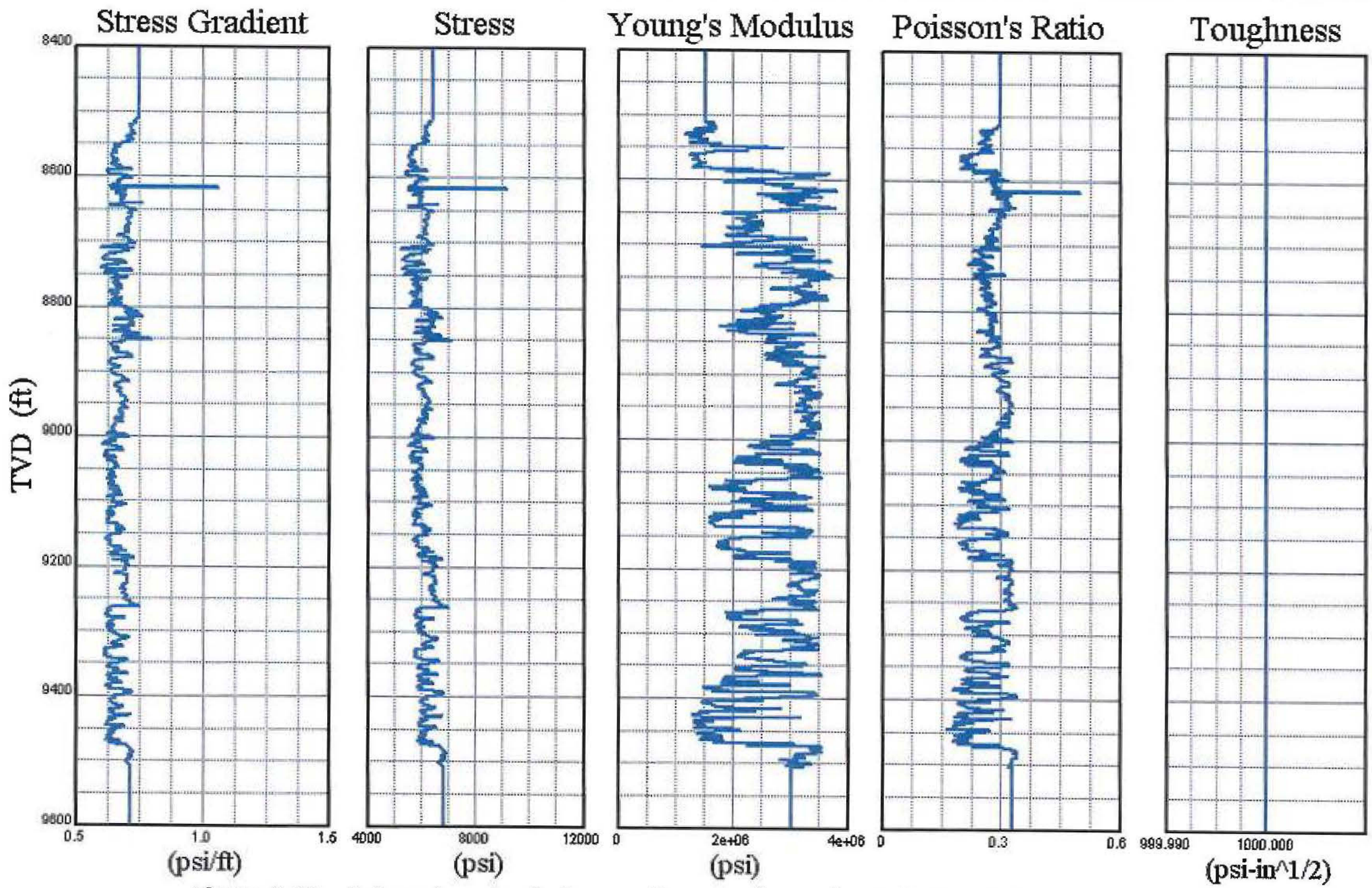

Figure A-10. Inferred mechanical properties over the perforated intervals (composite view).

APPENDIX B

RESULTS

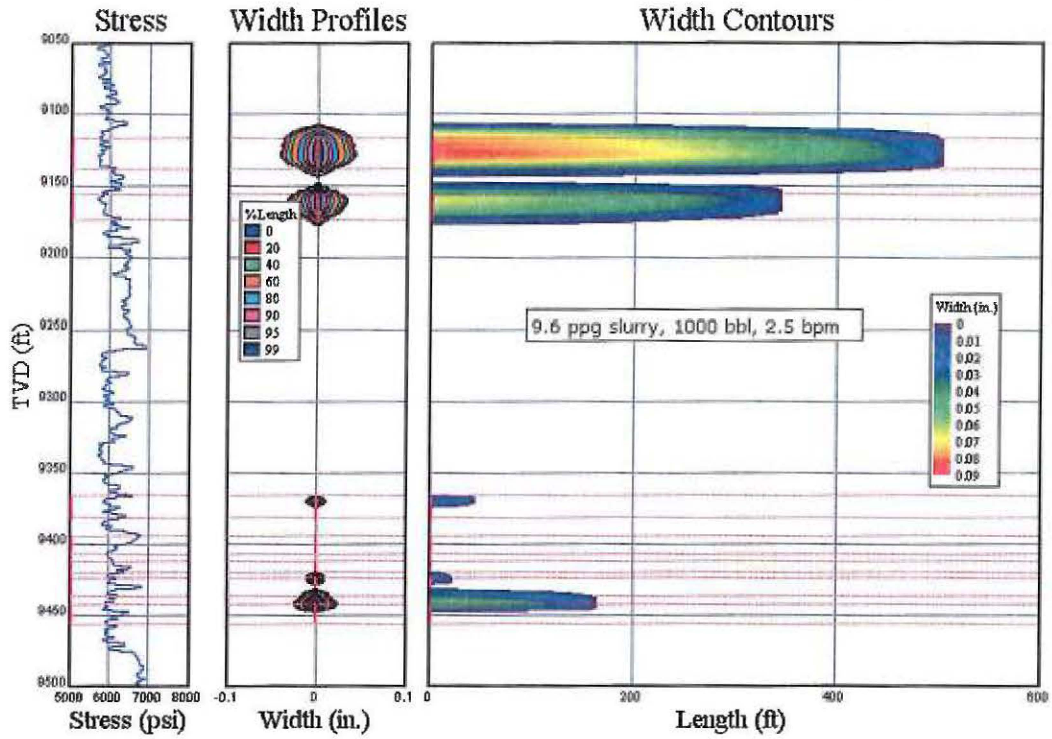

Figure B-1. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 9.6 ppg slurry, 1,000 BBL, injection into all Ivishak zones (Case 1).

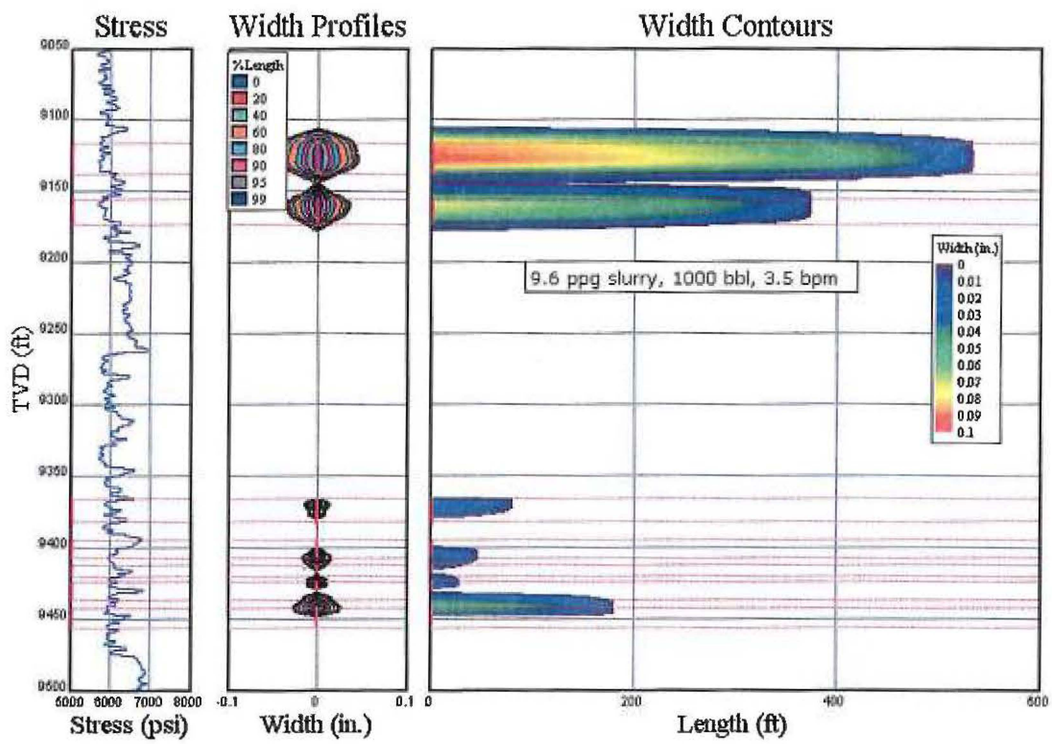

Figure B-2. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 9.6 ppg slurry, 1,000 BBL, injection into all Ivishak zones (Case 2).

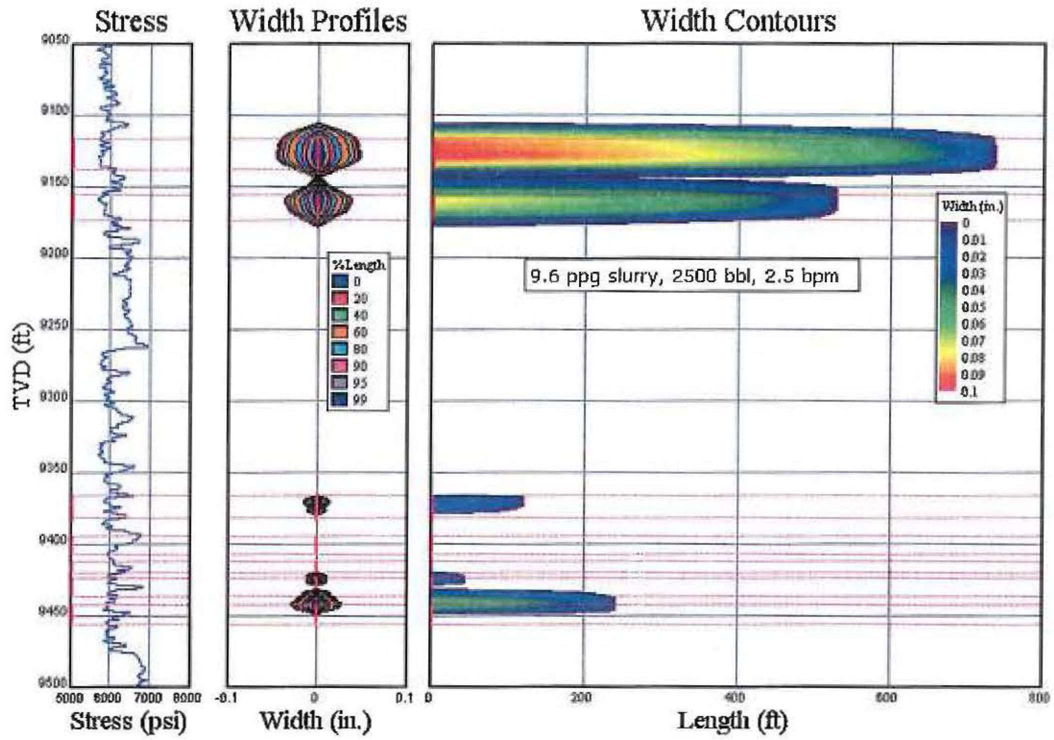

Figure B-3. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 9.6 ppg slurry, 2,500 BBL, injection into all Ivishak zones (Case 3).

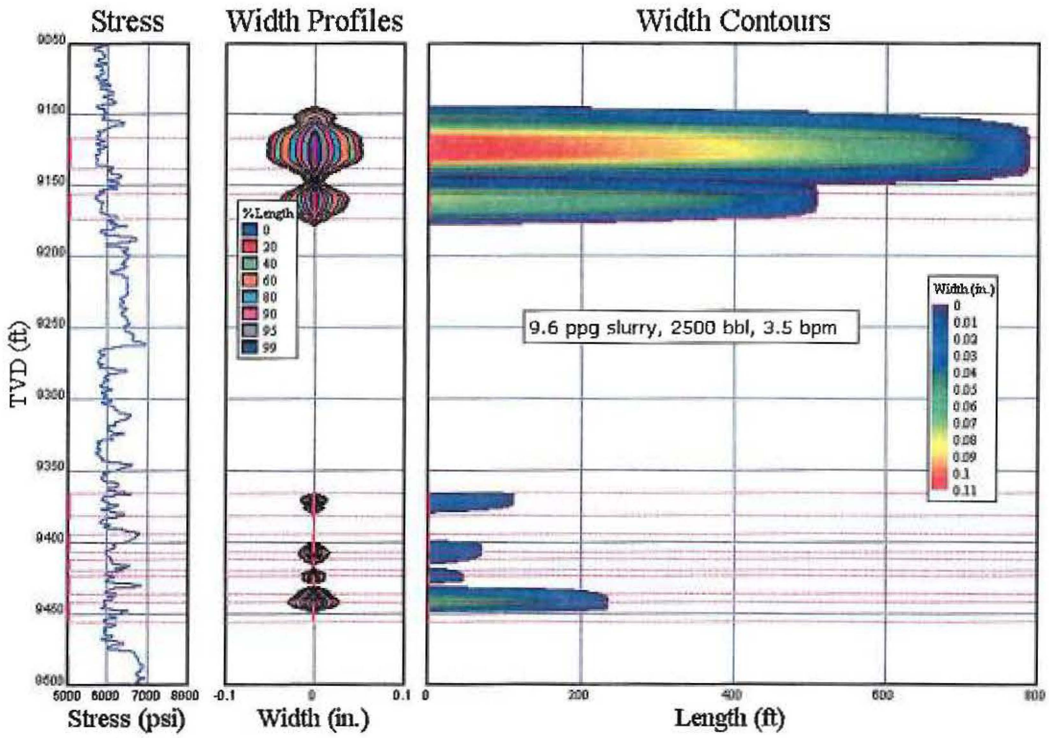

Figure B-4. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 9.6 ppg slurry, 2,500 BBL, injection into all Ivishak zones (Case 3).

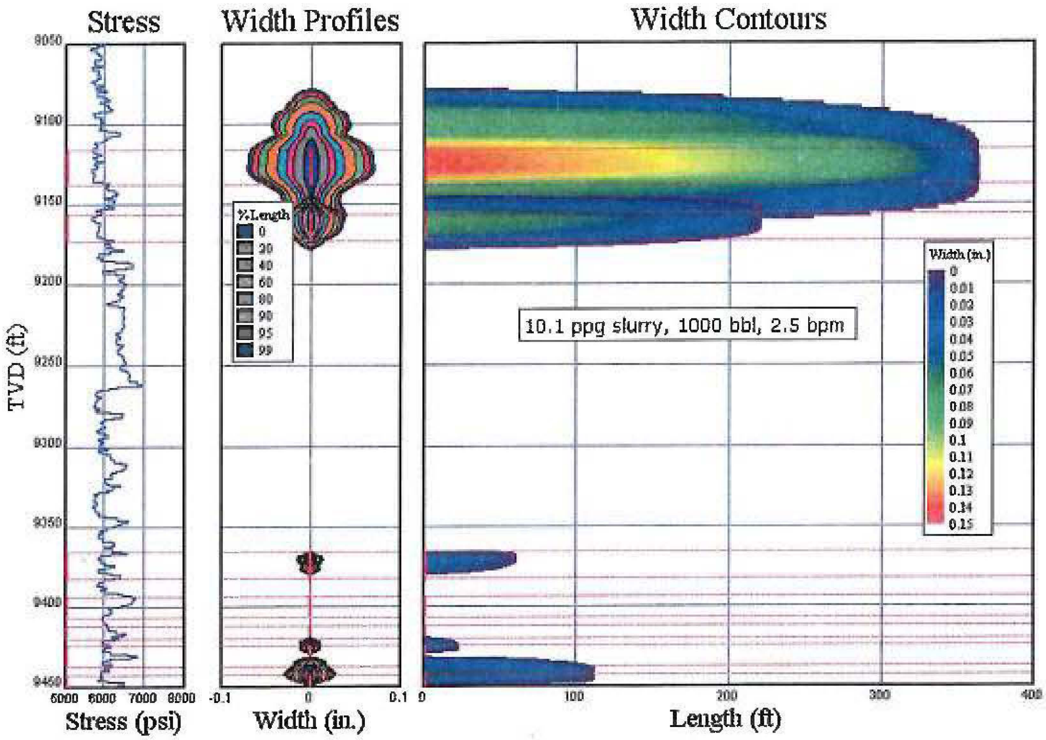

Figure B-5. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 10.1 ppg slurry, 1,000 BBL, injection into all Ivishak zones (Case 5).

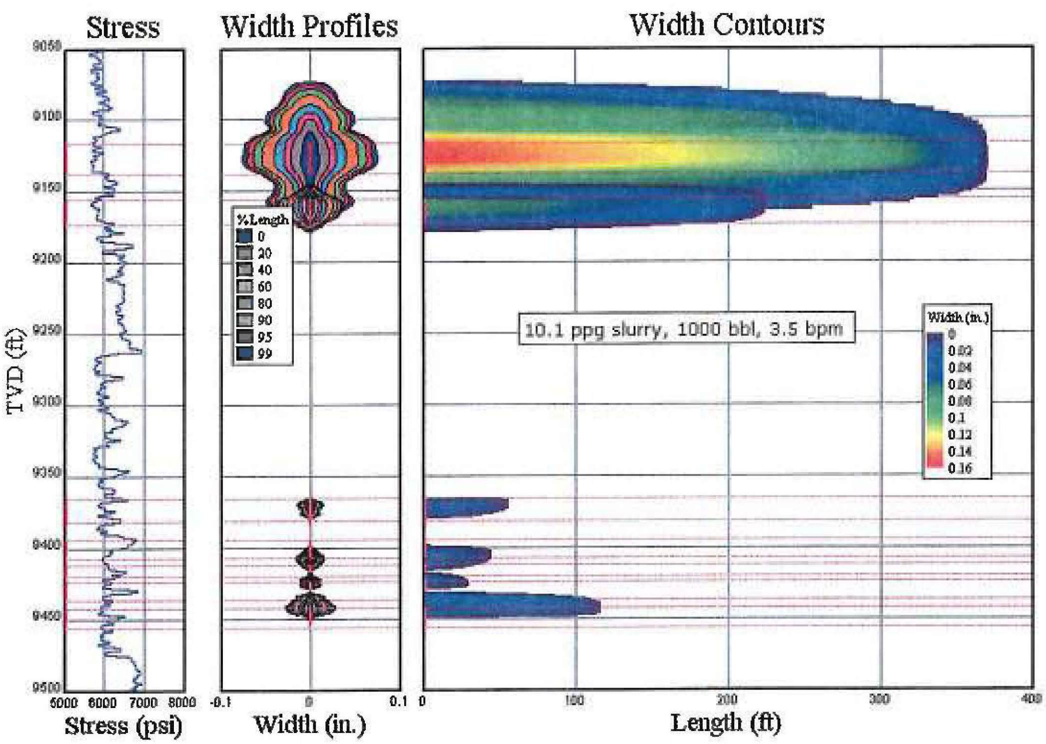

Figure B-6. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 10.1 ppg slurry, 1,000 BBL, injection into all Ivishak zones (Case 6).

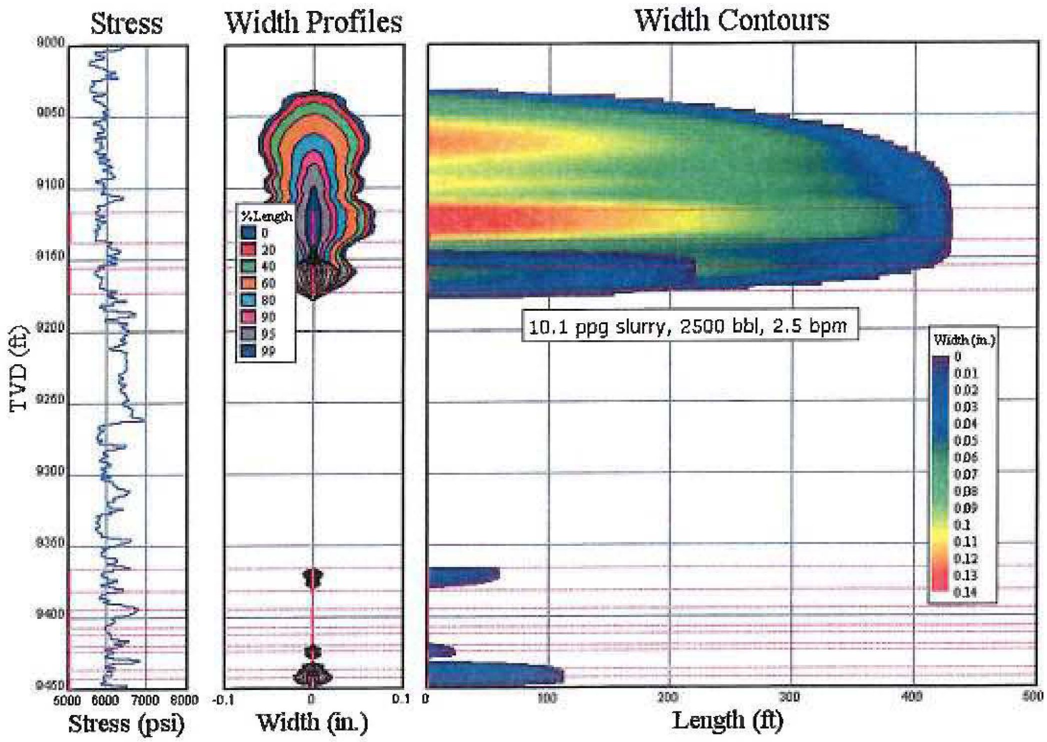

Figure B-7. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 10.1 ppg slurry, 2,500 BBL, injection into all Ivishak zones (Case 7).

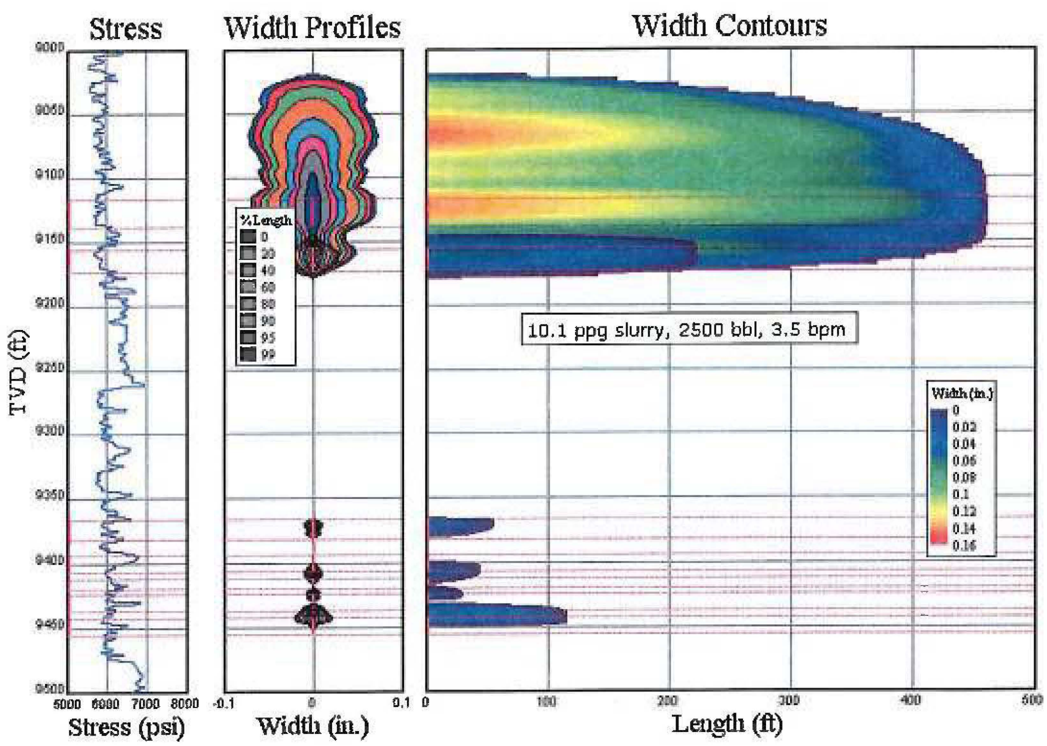

Figure B-8. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 10.1 ppg slurry, 2,500 BBL, injection into all Ivishak zones (Case 8).

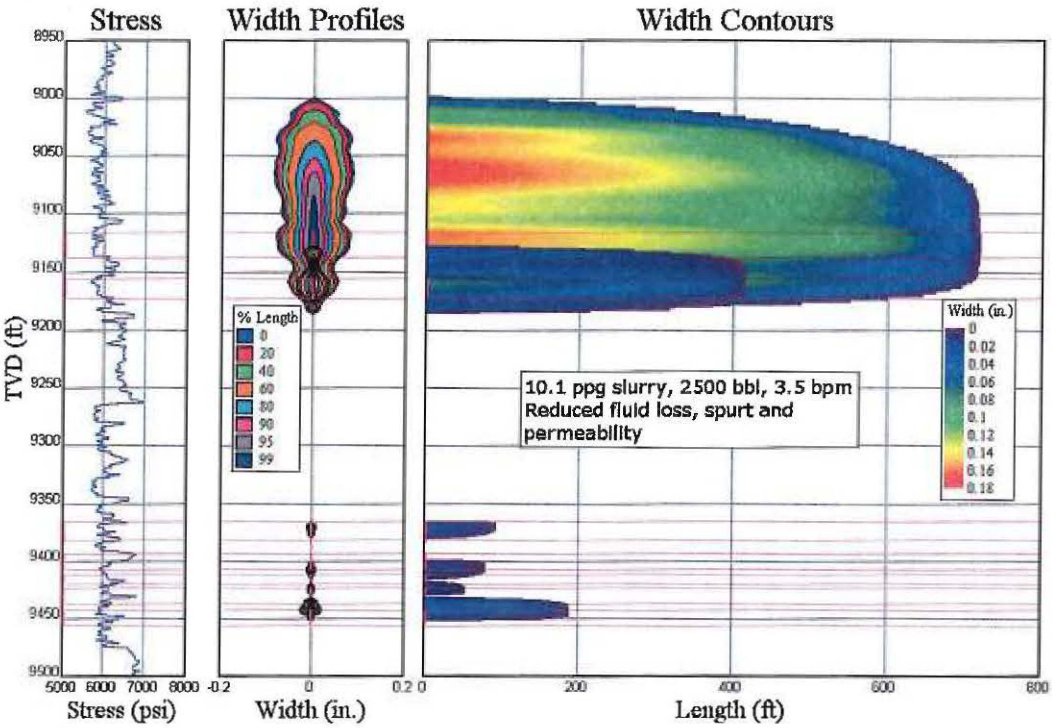

Figure B-9. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 10.1 ppg slurry, 2,500 BBL, injection into all Ivishak zones (Case 9). The difference is that the fluid loss coefficient and the permeability were both reduced to one-half of their baseline values.

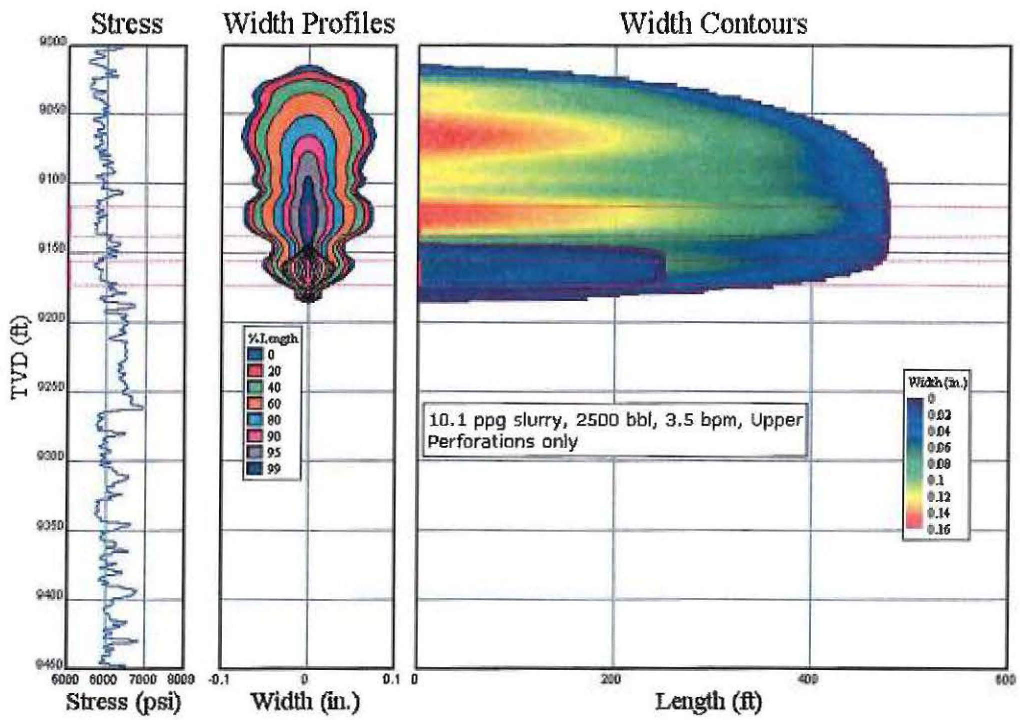

Figure B-10. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 10.1 ppg slurry, 2,500 BBL, injection into UPPER TWO Ivishak zones ONLY (Case 10).

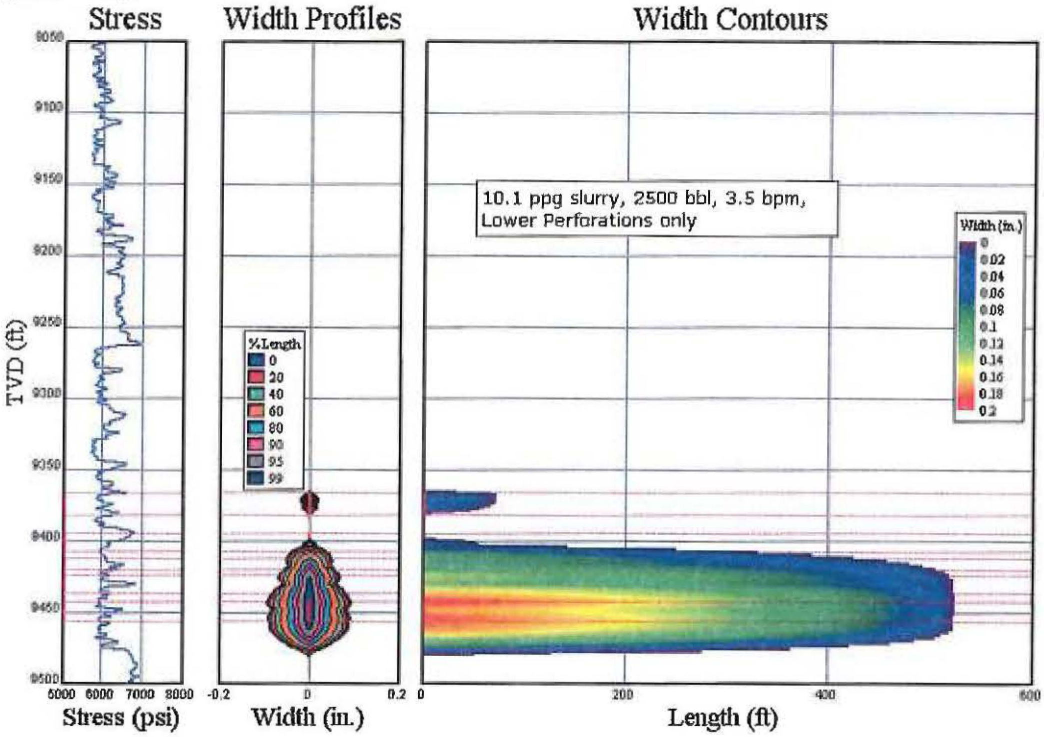

Figure B-11. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 10.1 ppg slurry, 2,500 BBL, injection into LOWER FIVE Ivishak zones ONLY (Case 11).

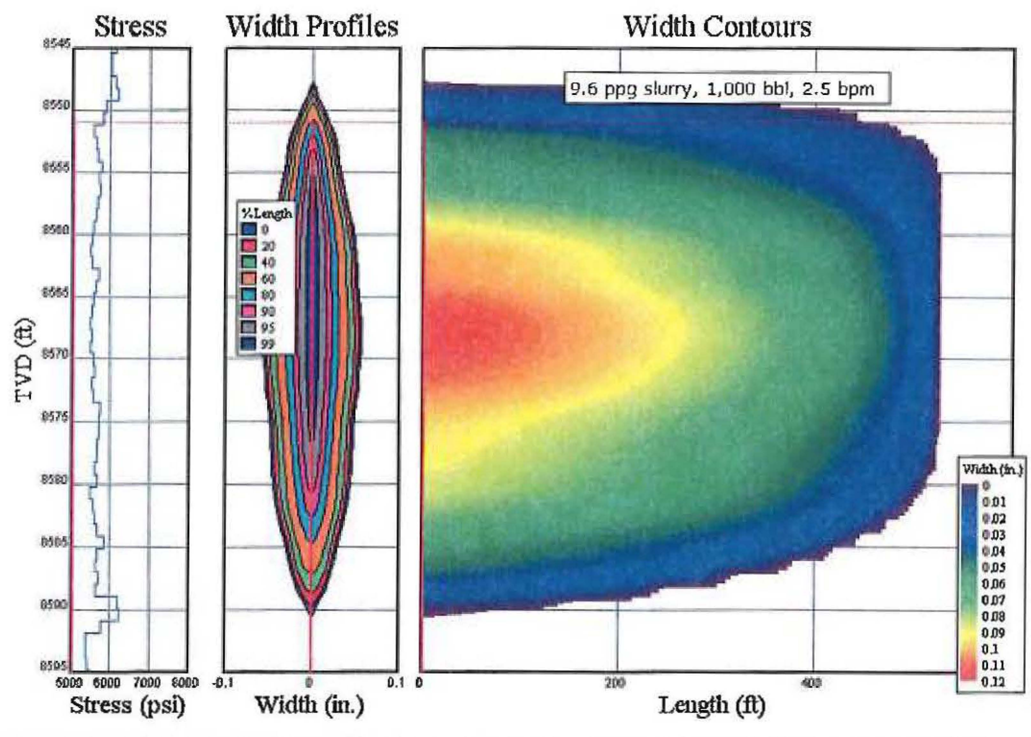

Figure B-12. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 9.6 ppg slurry, 1,000 BBL, injection into Sag River only (Case 12).

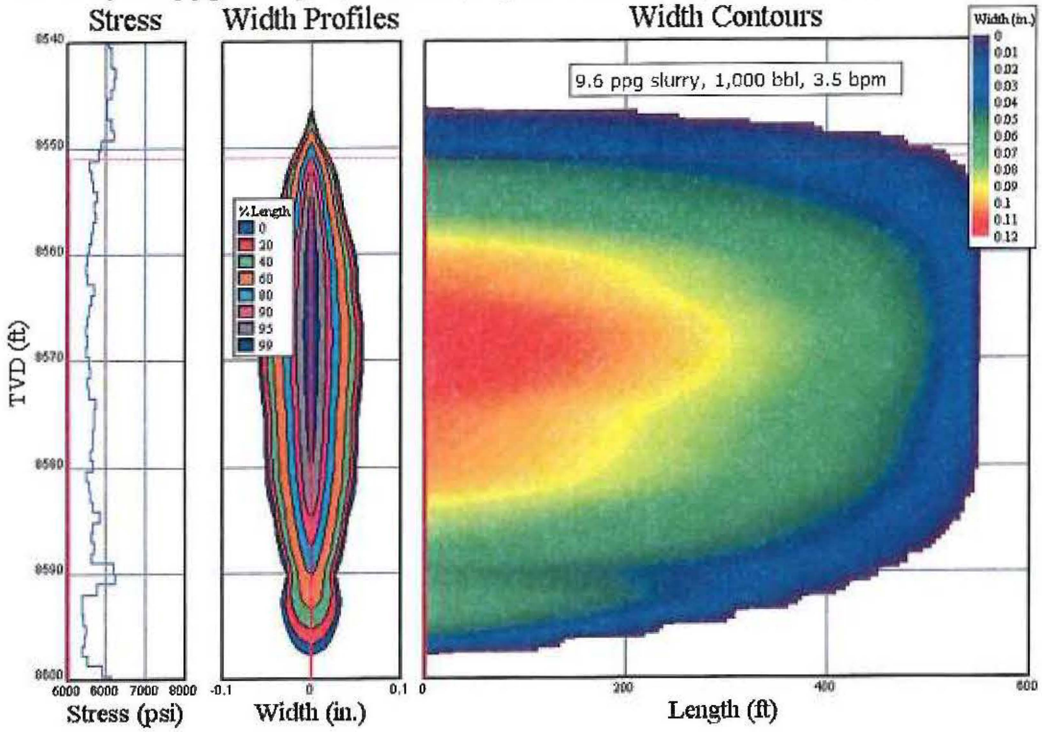

Figure B-13. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 9.6 ppg slurry, 1,000 BBL, injection into Sag River only (Case 13).

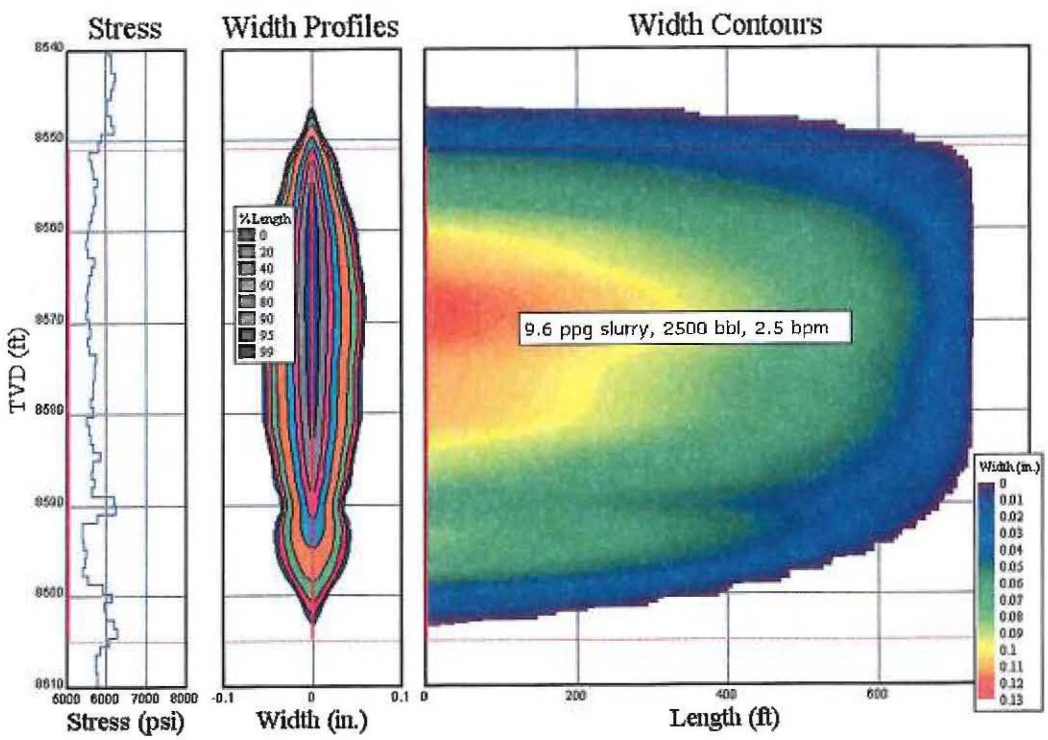

Figure B-14. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 9.6 ppg slurry, 2,500 BBL, injection into Sag River only (Case 14).

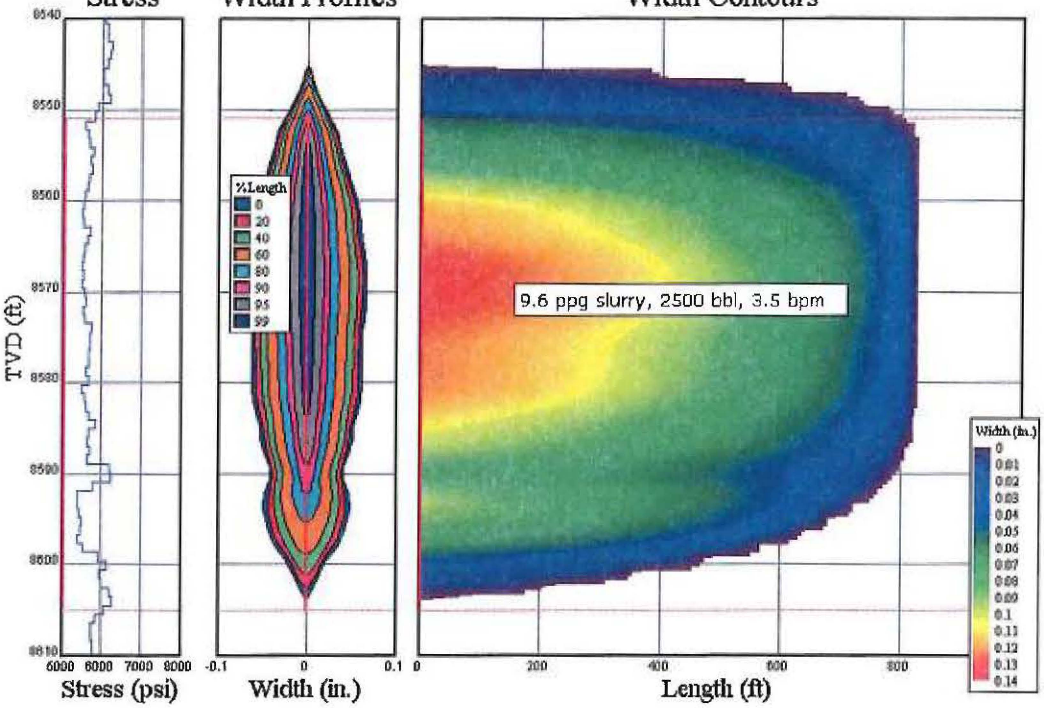

Figure B-15. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 9.6 ppg slurry, 2,500 BBL, injection into Sag River only (Case 15).

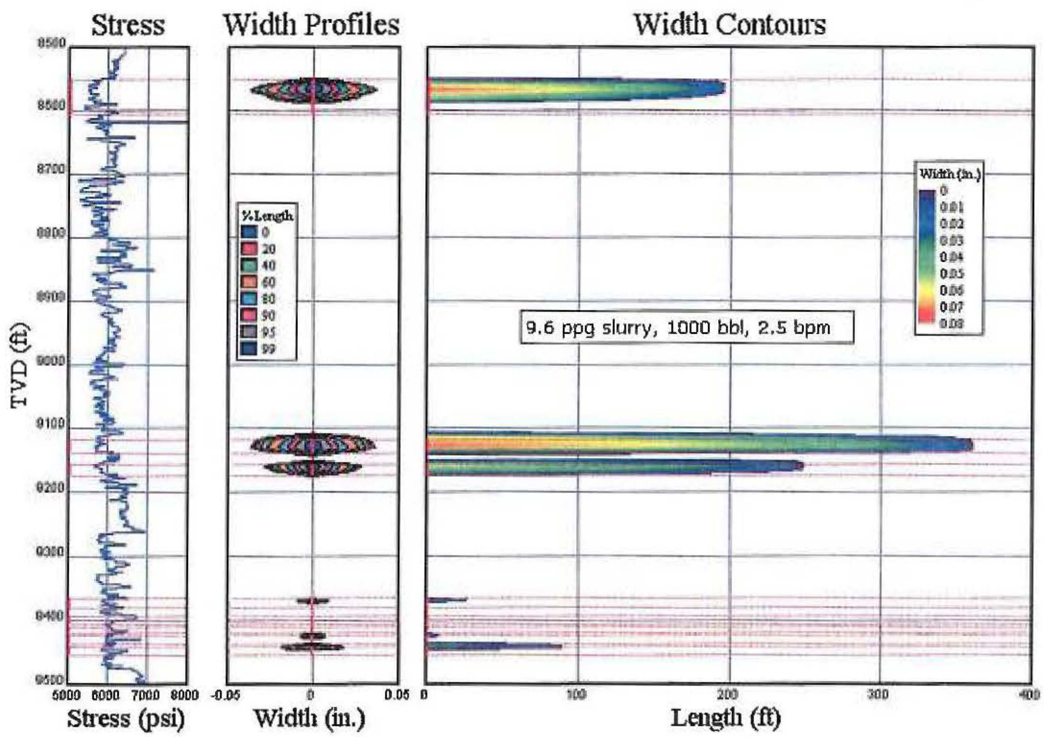

Figure B-16. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 9.6 ppg slurry, 1,000 BBL, injection into all Sag River and Ivishak zones (Case 16).

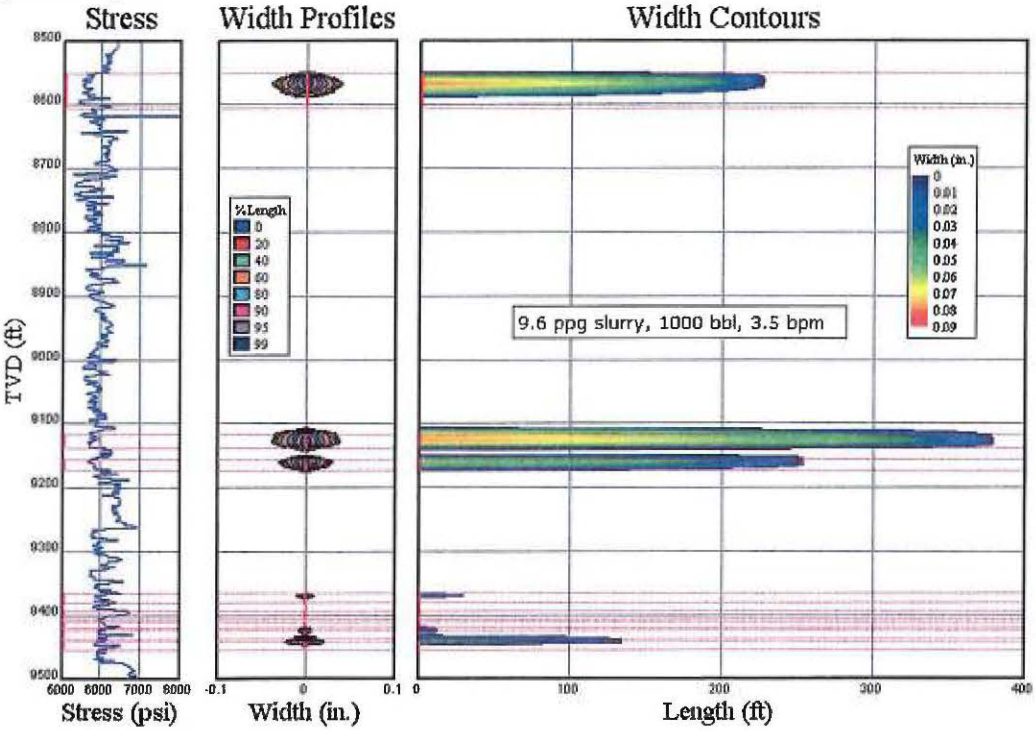

Figure B-17. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 9.6 ppg slurry, 1,000 BBL, injection into all Sag River and Ivishak zones (Case 17).

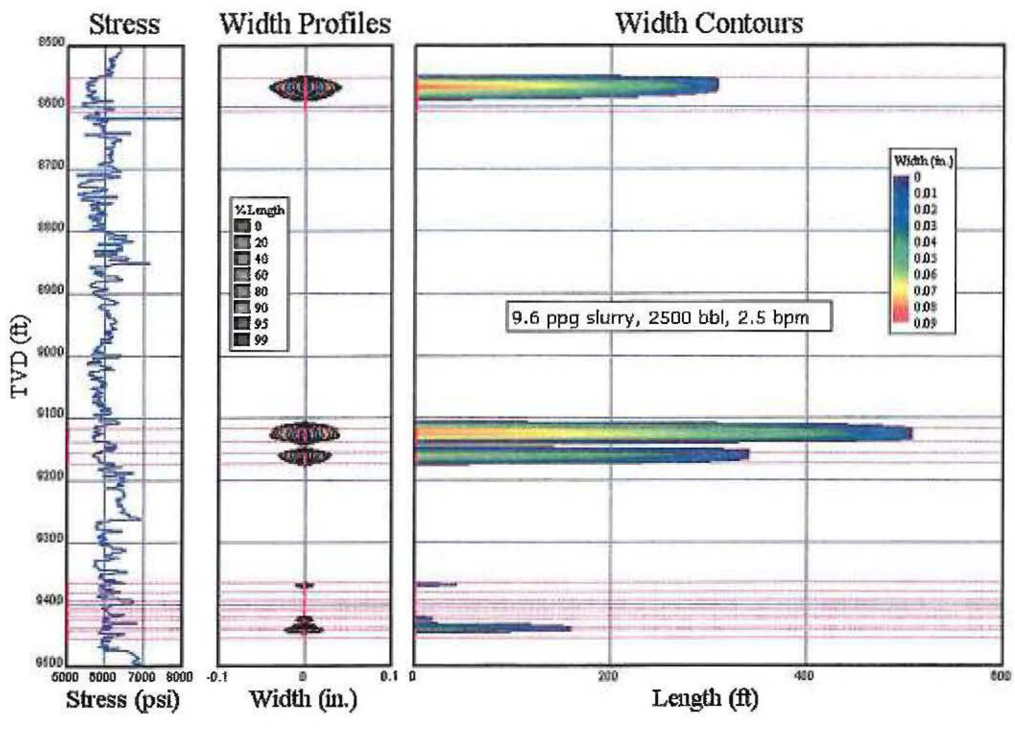

Figure B-18. This is the inferred geometry after flush (displacement volume) at shut-in for 2.5 BPM, 9.6 ppg slurry, 2,500 BBL, injection into all Sag River and Ivishak zones (Case 18).

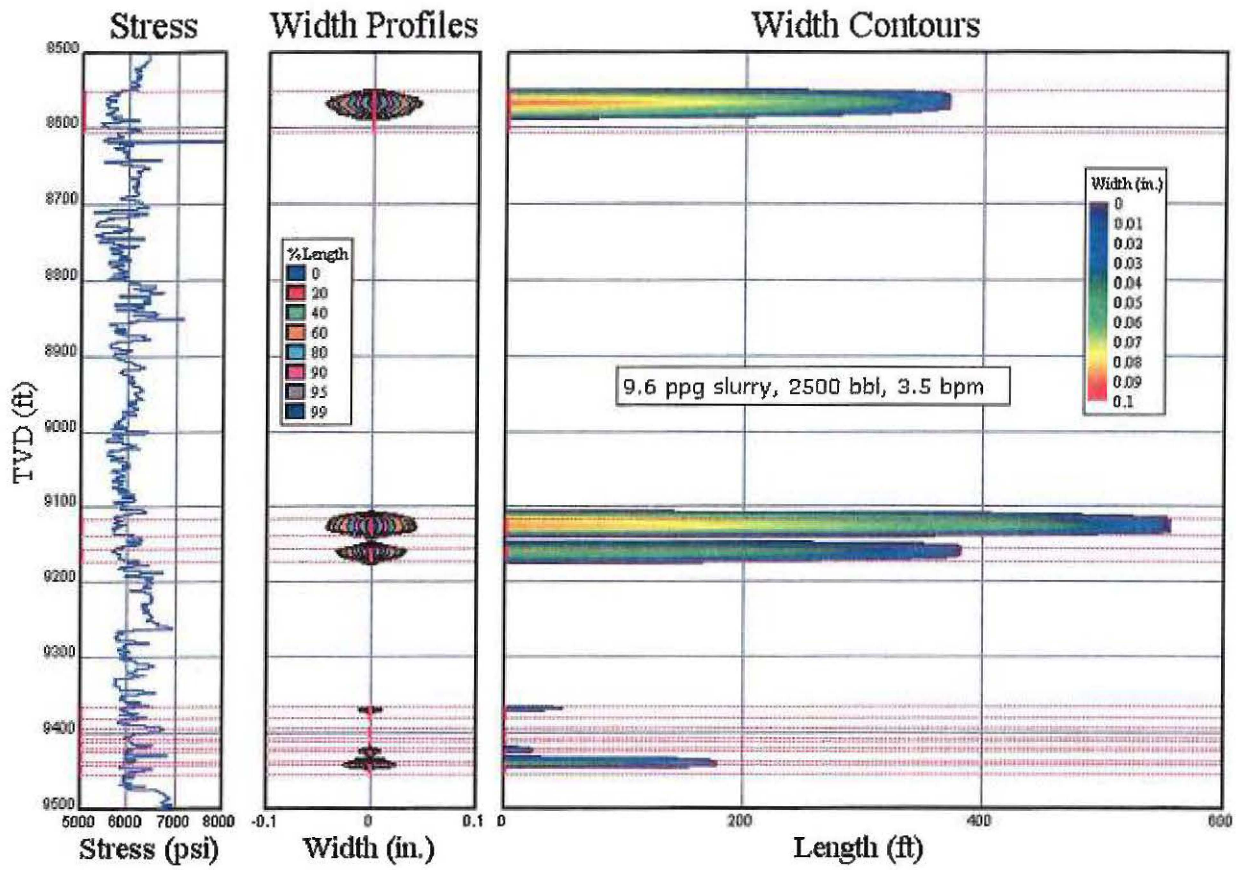

Figure B-19. This is the inferred geometry after flush (displacement volume) at shut-in for 3.5 BPM, 9.6 ppg slurry, 2,500 BBL, injection into all Sag River and Ivishak zones (Case 19).